

SB

138

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Sectional Analysis

Commercialization of North Slope Natural Gas

SB 138 / 28-GS2806\A

February 7, 2014

Department of Law

Senate Resources

Three subject areas of SB 138

- Sections 1 – 9** amend AS 31.25 to expand the general purposes of the Alaska Gasline Development Corporation (AGDC) to include a subsidiary corporation of the state to pursue an equity option in the midstream portion of a gas pipeline and in associated treatment and liquefaction.
- Sections 10 – 22** amend statutes related to the authority of the Department of Natural Resources (DNR) commissioner to negotiate agreements and confidentiality for negotiations, related to the authority of the DNR commissioner to work with lessees to amend certain oil and gas leases and related to the sales of royalty in-kind to include tax gas.
- Sections 23 - 47** amend tax statutes related to authority of the commissioner of the Department of Revenue (DOR) to participate in negotiations with the DNR commissioner, confidentiality, the corporate income tax and the oil and gas production tax - the most significant proposal is to amend the oil and gas production tax to levy a gross tax on gas after 2022, and to allow, for certain leases, a producer to pay tax on gas in kind.

Terms

"large-diameter natural gas pipeline project"

Bill sections 1 – 9

"statutory subsidiary"

Bill section 7

"tax as gas or TAG"

Bill section 29 - not used in bill – refers to production tax paid in gas for production on and after January 1, 2022 from modified leases.

"modified leases"

Bill sections 13 and 14 - not used in the bill – refers to North Slope leases modified based on certain determinations.

"North Slope natural gas project"

Bill section 19

Creation of the statutory subsidiary

Section 1 expands the purpose of the AGDC

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1 the fullest extent possible.
2 (1) advance an in-state natural gas pipeline as described in the July 1,

20 (4) advance to develop a large-diameter natural gas pipeline
21 project other than the in-state natural gas pipeline described in (1) of this section
22 by acquiring an equity interest in a large-diameter natural gas pipeline project
23 through the subsidiary under AS 31.25.122;

24 (5) advance to develop, finance, construct, and operate facilities
25 for liquefaction and treatment in connection with a large-diameter natural gas
26 pipeline project other than the in-state natural gas pipeline described in (1) of
27 this section through the subsidiary under AS 31.25.122.

28
29 **Sec. 31.25.010. Structure.** The Alaska Gasline Development Corporation is a
30 public corporation and government instrumentality located for administrative purposes
31 in the Department of Commerce, Community, and Economic Development, but

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3
New Code Underlined DELETED TEXT BRACKETED

SB 138

Creation of the statutory subsidiary

Section 7 - AS 31.25.122 - establishes a **statutorily created subsidiary** and instrumentality of the state to hold the state's equity interest in the large-diameter LNG pipeline and associated facilities.

- **Subsidiary** - hold state equity ownership and act as its investment entity during the LNG project, and return revenues to the state.
- **Subsidiary** - in AGDC chapter for administrative purposes; has a separate legal existence.
- **Advantages of a statutory subsidiary instrumentality of the state** - powers flow directly from legislature, and over which the state maintains control include
 - **State Revenues** - flow net revenues received from the state's equity interests into the state permanent fund and the general fund,
 - **State Revenues Federal Tax Exempt** - maintain state revenues exempt from the Federal income tax.

Creation of the statutory subsidiary

Attributes of the statutory subsidiary as instrumentality of the state include

- Created by statute as an instrumentality of and integral part of the state and state has authority to terminate the Subsidiary,
- State directs its revenues,
- Its employees are state employees,
- The state retains control over its operations,
- It is subject to general laws that apply to other governmental entities.
- The governor retains board member appointment and termination powers.

Creation of the statutory subsidiary

Section 4 amends the in-state natural gas pipeline fund language to clarify that money appropriated to the AGDC in-state natural gas pipeline fund may be used for the in-state natural gas pipeline, but not for the purpose of advancing the large-diameter LNG project.

Section 5 establishes a new separate fund in the statutory subsidiary for the large-diameter LNG project and provides that money appropriated to the LNG project fund is separately accounted for to be used for purposes of the large-diameter LNG project and not for the in-state natural gas pipeline.

Department of Natural Resources and Department of Revenue Participation in a North Slope natural gas project

Sections 10 and 11 provide authority for the DNR commissioner to

- Enter short-term commercial agreements for project services;
- Negotiate terms for inclusion in proposed contracts related to a North Slope natural gas pipeline;
- Enter into confidentiality agreements related to the negotiations and contracts;
 - A proposed contract presented to the legislature for the purpose of obtaining authorization is *not confidential*.
- Manage project services and take custody of the TAG.

Department of Natural Resources and Department of Revenue Participation in a North Slope natural gas project

Sections 23 and 24 provide that the DOR commissioner shall

- consult with the DNR commissioner on negotiations associated with a North Slope natural gas project;
- direct the disposition of revenues received from the TAG.

Oil and Gas Lease Modifications for a North Slope natural gas project

Bill sections 13 and 14 –AS 38.05.180(hh)

Provide authority for the DNR commissioner to propose modifications to existing oil and gas leases.

Oil and Gas Lease Modifications for a North Slope natural gas project

What may the DNR commissioner include in the proposed lease modifications ?

- 2 (1) switching between taking the state's royalty gas in value and in
3 kind to ensure that the state's actions do not unreasonably
4 (A) cause the lessee or other person to bear disproportionate
5 transportation costs with respect to the state's royalty gas; or
6 (B) interfere with long-term marketing of natural gas by the
7 lessee or other person;
8 (2) providing a method for establishing a fair market value for each
9 component of the state's royalty gas and using appropriate adjustments to reflect fair
10 market value deductions for actual and reasonable transportation and processing costs
11 for the state's royalty gas from the North Slope to the first destination market; and
12 (3) establishing fixed royalty rates and modifying net profit shares
13 under leases subject to this subsection.

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ing between taking the state's royalty gas in value and in
s actions do not unreasonably
cause the lessee or other person to bear disproportionate
with respect to the state's royalty gas; or
interfere with long-term marketing of natural gas by the

ing a method for establishing a fair market value for each
valty gas and using appropriate adjustments to reflect fair
r actual and reasonable transportation and processing costs
on the North Slope to the first destination market; and
hing fixed royalty rates and modifying net profit shares
subsection

nacted in sec. 13 of this Act, is amended to read:
ing any other provisions of this chapter, if the commissioner
tion that a North Slope natural gas project has sufficient
work plan and budget necessary to support major permits
quired by state and federal agencies, and sufficient
sses, the commissioner may propose modifications to

ing between taking the state's royalty gas in value and in
s actions do not unreasonably
cause the lessee or other person to bear disproportionate
with respect to the state's royalty gas or gas delivered to
43.55.014(b); or

interfere with long-term marketing of natural gas by the
n.

ing a method for establishing a fair market value for each
valty gas and using appropriate adjustments to reflect fair
r actual and reasonable transportation and processing costs

for the state's royalty gas from the North Slope to the first destination market; and

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SB 138

Oil and Gas Lease Modifications for a North Slope natural gas project

What is the process for the commissioner of the Department of Natural Resources to propose lease modification?

- The commissioner makes a **written determination** that a North Slope natural gas project has
 - Sufficient **financial commitment** for a work plan and budget necessary to support major permits and regulatory filings required by state and federal agencies; and
 - Sufficient **commitment of gas** by lessees.
- **Concurrence of lessees** to the proposed modifications.

Tax As Gas “TAG”

Bill section 29

What gas may be part of the TAG?

- Taxable gas
- Produced from a modified lease
- On and after January 1, 2022
- Subject to an irrevocable election by a producer to pay a production tax in kind
- **AS 43.55.014(a) & (b)**

TAG

Why may the DOR allow a producer to make an *irrevocable election* for payment as the TAG?

- The *irrevocable* nature of the election provides **stability for the state** and the producers.
- The *election* for the TAG recognizes the **distinction between royalty and tax.**
- “This election, like RIK, is ‘subject to the execution of project enabling contracts including satisfactory arrangements for disposition of the State Gas Share of LNG’ “.

TAG

What is the levy on the TAG?

- **10.5% of the taxable gas produced**
- **AS 43.55.014(b)**

When is the levy on the TAG?

- **when and as that gas is produced**
- **AS 43.55.014(b)**

TAG

What if there is a tax deficiency on the TAG?

- The amount of the deficiency and the tax amount on which the interest or penalty percentage is calculated will be treated (for the calculation) as if the tax was levied under AS 43.55.011(e)(i.e., payable in money rather than in kind).
- **AS 43.55.014(d)**

How will the TAG be reported in annual filings?

- The producer is required to identify the gross amount of gas produced from each lease or property subject to an election for payment in kind and the amount of gas delivered to the state.
- **Bill section 37 – AS 43.55.030(a)(3)**

What will be public information about the TAG?

- **Bill section 25** - provides that the **name of the person** that has made an election for the TAG and **the amount of gas produced** from each lease or property subject to the TAG election is **public information**.

TAG

How does the state take the TAG?

- The TAG is delivered to the state at the entrance of the transportation facility specified by the state.
- The DNR manages the custody and disposition of the gas delivered to the state.
 - AS 43.55.014(b) & (c)

How does the state receive revenues from the TAG?

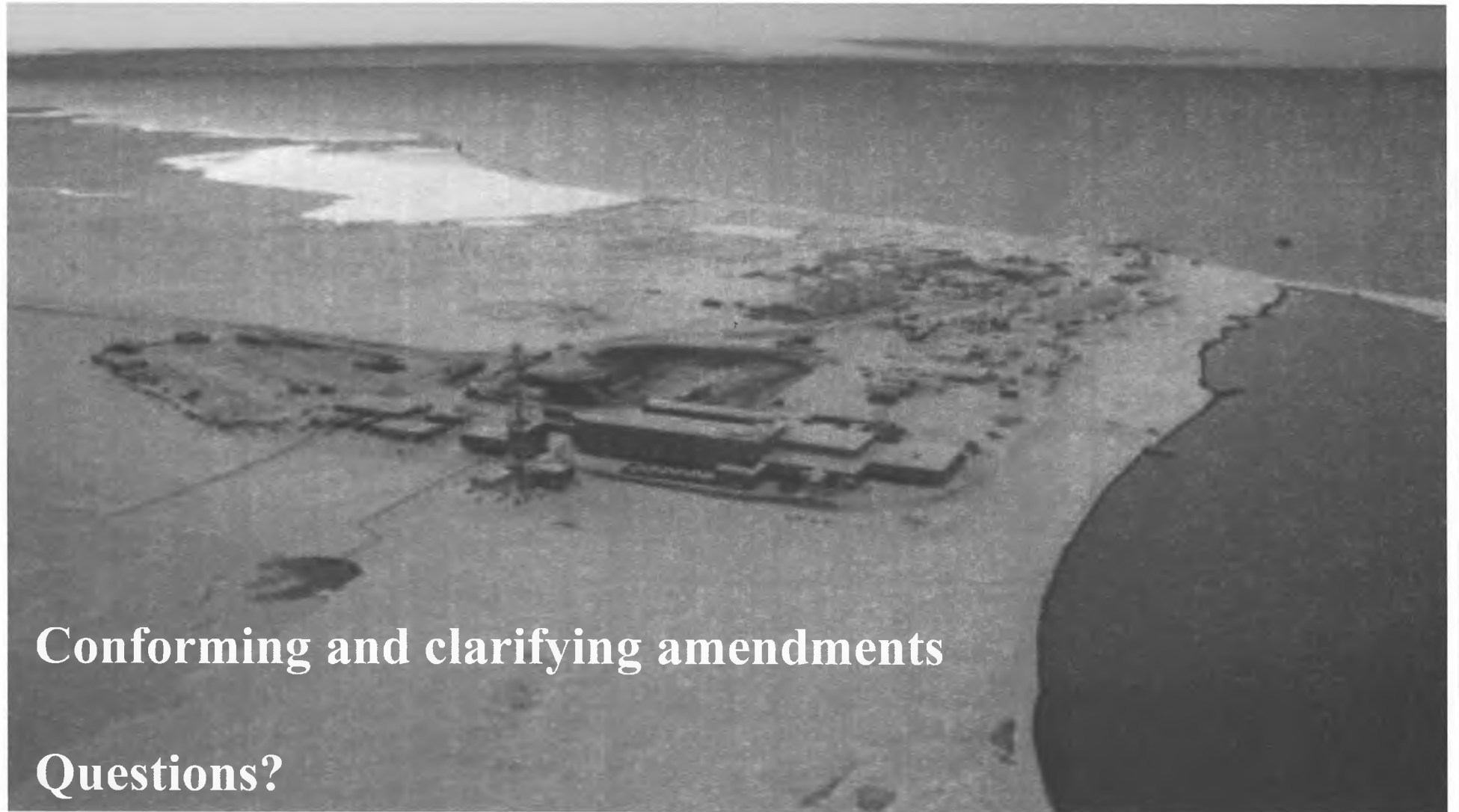
- The sales of the TAG are subject to the same provisions as sales of royalty gas in kind.
 - Bill sections 15-18
- The DOR commissioner directs the disposition of revenues received from the TAG.
 - Bill section 24

What would the Oil and Gas Production Tax look like for oil and gas produced on and after January 1, 2022?

- **Bill sections 27-47.**
- **TAG = Levy of 10.5% of the gas, otherwise taxable under AS 43.55.011(e)(3), produced from a modified lease that a producer has made an irrevocable election for payment in kind of the gas.**
 - **Bill section 29.**
- **Levy of 35% of the production tax value of taxable oil produced.**
 - **Bill section 27**
- **Levy of 10.5 % of the gross value at the point of production for taxable gas.**
 - **except for gas produced from modified leases that have elected the TAG.**
 - **Bill section 27.**
- **North Slope minimum tax = Levy of 4%-0% of the gross value at the point of production for North Slope oil depending on the price of ANS.**
 - **Bill section 28 – AS 43.55.011(f)(2).**
- **“Middle Earth” oil and gas production: May be subject to AS 43.55.011(p) tax ceiling and AS 43.55.024(a) and (b) tax credit.**

SB 138 does NOT change

- The Alaska Gasline Development Corporation's core mission, AS 31.25.005(1)-(3).
- The Oil and Gas Exploration, Production, and Pipeline Transportation Property Taxes, AS 43.56.
- Disposition of royalty and tax revenues.
- Current oil and gas production tax limitations.



Conforming and clarifying amendments

Questions?



Introducing SB 138

A Presentation to the Senate Resources Committee

Putting the Guidance Documents (HOA + MOU) in Context

February 7, 2014

Department of Natural Resources

**Joe Balash
Commissioner**

Department of Revenue

**Michael Pawlowski
Deputy Commissioner**

Guidance Documents & SB 138

Heads of Agreement (HOA)

- Describes roadmap to advance project through phased process.
- Describes understanding and consensus on key terms.

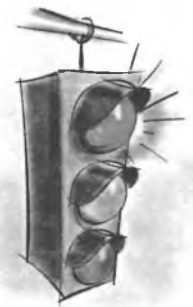
Memorandum of Understanding (MOU)

- Describes agreement to transition from AGIA License to a more traditional commercial relationship.
- Describes key commercial terms for that relationship.

HOA and MOU
Describe how SB 138
would be used.

Senate Bill 138

- **Participation** in the AKLNG Project.
- **Percentage** of State Gas Share and Participation in the AKLNG Project.
- **Process** for development of Project Enabling Contracts and **Legislative oversight and approval** of future contracts.



Legislature
decides whether
to advance or
not.

Where We Are Today?

Pt. Thomson Settlement
Joint Work Agreements



Concept Selection

SB 138
Jan- April
2014

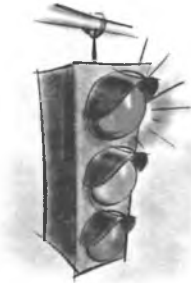
Pre-FEED

AGIA:
State: ~\$330 million
APP (TransCanada & EM):
~\$130 million

Denali
(BP & CP)
~\$200 million

State / TC MOU

Heads of Agreement



GO
All AGIA and Denali work is contributed to AKLNG with passage of enabling legislation (SB 138).

State & TransCanada mutually abandon AGIA license.

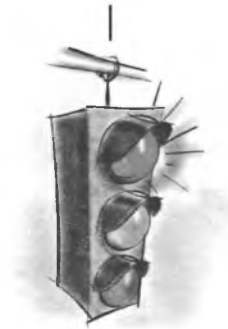
No more reimbursement.

Stop: does State buy \$130 million of APP data?

AGDC ASAP Advancing to 2015 Open Season (sharing w AKLNG) 

What Happens if SB 138 Passes?

**Pre-Front End Engineering & Design
(Pre-FEED)
12-18 months**



FEED
(Front-End
Engineering &
Design)

Estimated Cost: ~\$435 million
(Does not include costs upstream in Prudhoe Bay & Pt. Thomson)

Producer Share: ~\$348 - \$327 million

State/AGDC Subsidiary

Share: ~\$35 - \$43 million
(Does not include Agency/AGDC costs and contingency in support of project)

TransCanada: ~\$53 - \$67 million

**Legislative
Approval of
Contracts
Yes/No?**

GO

Exercise Option
for 40% of FEED =
\$21 - \$27 million?

Note: Savings with TransCanada include cash commitments by TransCanada for Pre-FEED costs which reduce State of Alaska appropriations by \$53 - \$67 million and seamless transition into Pre-FEED with personnel and data continuing to be committed to the project.

Stop

Pay TC Development
Costs (~\$53-\$67mm) +
7.1% AFUDC.

AGDC ASAP Advancing to 2015 Open Season (sharing w AKLNG)

What Happens after FEED?

**Front End Engineering & Design
(FEED)
2-3 years**

Estimated Cost: ~\$1,800 million
(Does not include costs upstream in Prudhoe Bay & Pt. Thomson)

Producer Share: ~\$1,440 - \$1,350 million

State/AGDC Subsidiary

Share: ~\$145 - \$180 million
(Does not include Agency/AGDC costs and contingency in support of project)

State/AGDC Subsidiary

Share (w Equity Option): ~\$310 - \$390 million

TransCanada: ~\$215 - \$270 million

TransCanada (w Option): ~\$130 - \$160 million

Note: FEED costs are VERY rough estimates and rounded!



**Final Investment
Decision ~
Construction**

**Approval by all
Parties &
Financing
Yes/No?**

Go Build

STOP

Pay TC development
costs (~\$183 - \$337 mm)
+ 7.1% AFUDC.

Note: FEED estimates based on Black & Veatch independent assessment of 4% of \$45 billion. 60%/40% Mid/Downstream.

AGDC Advancing Gas to Alaskans through interconnections etc.

Summary

- The Heads of Agreement (HOA) and Memorandum of Understanding (MOU) provide guidance on how the powers provided in SB 138 will be used.
- At each stage in the project there are “off-ramps” and decision points for Legislative and public review.
- Commitments by the State will be made commensurate with progress by the project.

THANK YOU

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Resources

<http://dor.alaska.gov/MAPActDocuments.aspx>

<http://gov.alaska.gov/parnell/priorities/resources/more-alaska-production-act.html>

www.dnr.alaska.gov/AKgas.htm



**BUILDING A
WORLD OF
DIFFERENCE**

FEBRUARY 10, 2014

ALASKA NORTH SLOPE ROYALTY STUDY

PRESENTATION TO SENATE RESOURCES COMMITTEE

PREPARED FOR THE STATE OF ALASKA



BLACK & VEATCH
Building a world of difference.

BLACK & VEATCH PRESENTERS



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NOTE ON ALASKA NORTH SLOPE ROYALTY STUDY

- **The Alaska North Slope Royalty Study was undertaken between June 2013 and November 2013 and, hence, preceded finalization of the Heads of Agreement (“HOA”) between ExxonMobil, ConocoPhillips, BP, TC Alaska, AGDC, and the State Administration as well as the Memorandum of Understanding (“MOU”) between the State Administration and TransCanada.**
- **While the study informed the State Administration as it negotiated the HOA and the MOU, the study, and this presentation summarizing it, do not analyze the specific terms within these agreements or their impacts on the competitiveness of the AKLNG project.**
- **The attached supplemental analysis summarizes ongoing analysis of some specific terms in the MOU and HOA and their impacts on the State of Alaska.**

EXECUTIVE SUMMARY – BACKGROUND & SCOPE



- The Alaska Liquefied Natural Gas (AKLNG) project is a proposed project to liquefy Alaska North Slope (ANS) gas and export it as LNG, primarily to Asian markets
- The project is comprised of three main components:
 - Gas treatment plant (GTP),
 - Pipeline
 - Liquefied natural gas (LNG) plant
- The total estimated capital cost of the project is \$45 billion falling within a range of \$39-\$54 billion
- Natural gas to supply the project is anticipated to come from the proven reserves at the Prudhoe Bay and Point Thomson units on the Alaska North Slope
- The key project sponsors are Exxon Mobil, ConocoPhillips and BP (referred to in this study as Producers) with potential participation by TransCanada and the State of Alaska
- Target final investment decision for the project is projected around 2017-18 with a commercial operation date around 2023-24

EXECUTIVE SUMMARY – BACKGROUND & SCOPE



- The AKLNG Project has recently seen momentum with the 3 Producers along with TransCanada coming together to evaluate and advance the AKLNG Project
- The AKLNG Project has the potential to provide hundreds of billions of dollars in value to the State of Alaska as well as the project's investors; the benefits to Alaskans include new revenues, affordable energy supplies, new jobs and economic activity
- The State of Alaska, Department of Natural Resources (DNR) commissioned a study to document and understand four major commercial elements that could influence the various stakeholders' returns from the AKLNG Project:
 - LNG markets
 - Supply chain elements
 - Fiscal framework – International and Alaska
 - Risk allocation/commercial structure

EXECUTIVE SUMMARY – BACKGROUND & SCOPE



- The purpose of this study is to provide information that can help the State to protect its royalty interest in the state's gas and ensure that the State maximizes the value of its natural gas
- The study examined how the State's fiscal terms with a particular focus on royalty terms can affect the success of the AKLNG project in its role as the principal land owner of the oil and gas resources of the North Slope
- The Study was undertaken by a team that included Black & Veatch and Daniel Johnston, Inc. under the leadership of DNR along with support and consultation by Department of Revenue (DOR). Additionally, inputs and assumptions of AKLNG Project sponsors were considered.

EXECUTIVE SUMMARY – BACKGROUND & SCOPE

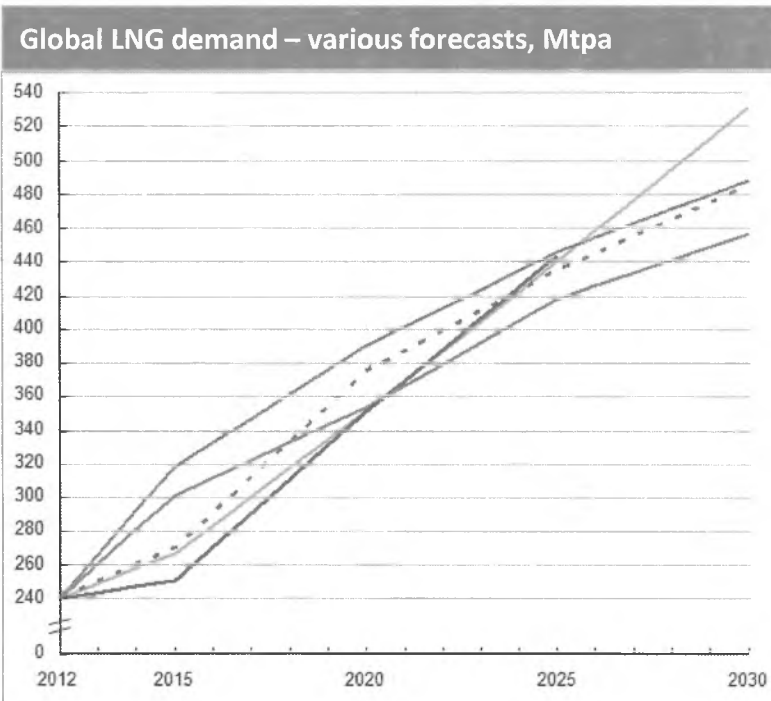


- Assessment of a project of the scope of AKLNG requires examination of numerous complex variables that cannot be determined with a high degree of certainty
- In most cases, a conservative approach was taken when applying forecasts and assumptions
- Many reasonable scenarios can be derived where the AKLNG project is economic, and vice versa
- It should be recognized that market and project related variables, that remain as yet unresolved, can modify the economics as presented here
- The findings in this study represent Black & Veatch's view based on the information available to date and do not necessarily represent the views of the State of Alaska

EXECUTIVE SUMMARY – KEY FINDINGS

LNG Markets

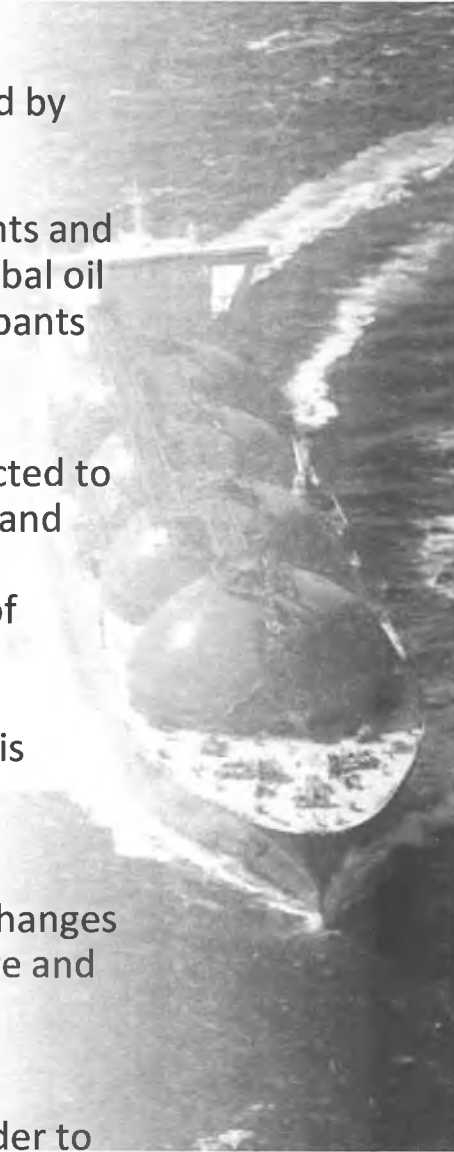
- The LNG market is characterized by highly capital intensive projects underpinned by long-term contractual relationships across the supply chain
- The LNG market is in an illiquid, opaque market consisting of very few participants and is structured on the basis of long-term, 20+ year contracts as opposed to the global oil market which is highly liquid, extremely transparent, comprised of many participants and is structured on the basis of short term trade



Note: Includes AKLNG, other new projects, and projects under development.

Source: Team Analysis, various demand studies

- Global LNG demand is projected to grow by 50% between 2013 and 2020 and to double by 2030. However potential sources of supply are expanding as well thereby creating significant competition for capturing this growing market
- AKLNG project could be economically feasible with changes to the project's cost structure and the state's fiscal framework
- AKLNG will have to compete successfully for buyers in order to meet its targeted 2024 in-service date



EXECUTIVE SUMMARY – KEY FINDINGS



Supply Chain Elements

- In line with the rising costs of LNG projects world-wide, AKLNG project cost estimates have risen by 67% since an equivalent project was evaluated in 2008 to a current estimate of \$45 Billion for the GTP, Pipeline and LNG liquefaction and marine facilities. Equivalent estimates from AKLNG project sponsors are in the range of \$37 - \$54 Billion.
- Large, complex LNG projects typically have an integrated commercial structure from production through liquefaction to give project sponsors maximum control across the supply chain.
- The AKLNG project is expected to have an integrated structure
- Ensuring transparency along the supply chain, open access for third parties and alignment of interests between the State and Producers become challenging with a Producer-owned integrated project.

EXECUTIVE SUMMARY – KEY FINDINGS

Fiscal Framework

- AKLNG is competing for capital with Producers' projects worldwide and for market share with other sources of supply.
- Similar to other oil and gas projects, LNG projects have either concessionary or contractual fiscal systems with total government take ranging from 45% - 80% for comparable LNG projects reviewed that have achieved commercial operation.
- Government take in Alaska in the 70% - 85% range is high for a complex LNG project, although overlapping with the range of government take for the other LNG projects reviewed. Expected IRR for the Producers of approximately 15% for the upstream and midstream components of the project may be insufficient for the Producers to move forward, given their investment alternatives and AKLNG project uncertainties.
- Changes to the project's cost structure and the State's fiscal framework can make the AKLNG Project more economic and competitive.



EXECUTIVE SUMMARY – KEY FINDINGS

Fiscal Framework

- Incentives including modifications in royalty and/or production tax are among the alternatives available to the State to help improve the relative competitiveness of the project under various scenarios.
- There are various risks to the State from significantly reducing or eliminating its royalty share;
 - Royalties represent Alaska's ownership stake and reducing royalties has implications for the Alaska Permanent Fund
 - Royalty reduction would not protect the State from risks posed by misalignment between the State and Producers interests wherein Producers are able to shift revenues between upstream and midstream components of the project to the detriment of the State



EXECUTIVE SUMMARY – KEY FINDINGS

Fiscal Framework

- In reviewing alternatives for royalty, an election by the State to take its royalty in-kind (RIK) could result in a substantial increase in the State's risk exposure and potential loss of royalty value.
 - An election by the State to take its royalty in-kind could necessitate the need for the State to enter into a large number of complex commercial agreements. The State would be disadvantaged in the creation of such agreements by its statutory and regulatory structure (e.g., the need for legislative modifications), its inexperience in LNG negotiation, its status as a new entrant to the market, and the lack of an LNG supply portfolio to optimize. Risks associated with RIK could result in lower pricing for our LNG
 - Producers have more experience managing the exposures to market risk
- An election by the State to take its royalty in value presents potential for dispute on valuation and deductions and misalignment of interests with the Producers.
 - However, the State has experience in addressing these challenges through settlement agreements that provide more certainty and clarity



EXECUTIVE SUMMARY – KEY FINDINGS

Risk Allocation

- Oil and LNG prices and capital costs emerge as the key factors among the various risks impacting the AKLNG project's economics
- Direct equity participation in the project can align the State with the Producers and reduce the cost structure of project for project sponsors but potentially exposes the State to additional risks
- Commercial terms related to equity participation such as position on the management committee and voting rights will determine the extent to which the State can achieve its objectives for open access and transparency



EXECUTIVE SUMMARY – CONCLUSIONS



- The AKLNG Project can be economically feasible and competitive with changes to the project's cost structure and the State's fiscal framework
- Fiscal and non-fiscal incentives can aid in improving the commercial attractiveness of the project
 - Fiscal – cost sharing, reduction in government take
 - Non-fiscal – stabilization provisions, modifications to existing lease terms such as the notice period of the State's rights to switch between RIK and RIV
- Integrated project ownership of AKLNG by the Producers presents the risk of misalignment wherein project revenues could be moved between the upstream and the midstream components to maximize value to the Producers. These decisions could potentially be to the detriment of the State.

EXECUTIVE SUMMARY – CONCLUSIONS



- Fiscal structure changes beyond stand-alone royalty share or tax rate modification can help in improving project economics and creating alignment:
 - Direct participation by the State in the project
 - Establishment of a gross share of gas in lieu of production tax
- Direct state equity participation in the project can provide key benefits to the State including :
 - Create alignment of interests;
 - Create transparency through the midstream portion of the supply chain;
 - Facilitate third-party access to the mid-stream;
 - Potentially increase State cash flows, and improve producer economics.

EXECUTIVE SUMMARY – CONCLUSIONS



- Going further, establishment of a gross share of gas in lieu of production tax and corresponding equity investment in the project may provide the needed alignment for a competitive project such that the State can maximize the value of its resources.
- The State has the ability to lessen project risk, but will need to weigh those opportunities circumspectly - risk mitigation and commercial agreements need to be addressed carefully to define the State's rights and obligations, manage risk exposure and to achieve objectives of transparency and open access for third parties

LNG MARKETS – SCOPE



- LNG Markets
- Supply Chain Elements
- Fiscal Framework
- Risk Allocation & Fiscal Structure

- Overview of how LNG is being traded and valued in various markets that are available to AKLNG Project
- Analysis of historical and future global LNG pricing trends
- Discussion of supply and demand projections in the LNG market and implications for AKLNG Project

CURRENT LNG MARKET REALITIES

Demand/ key markets

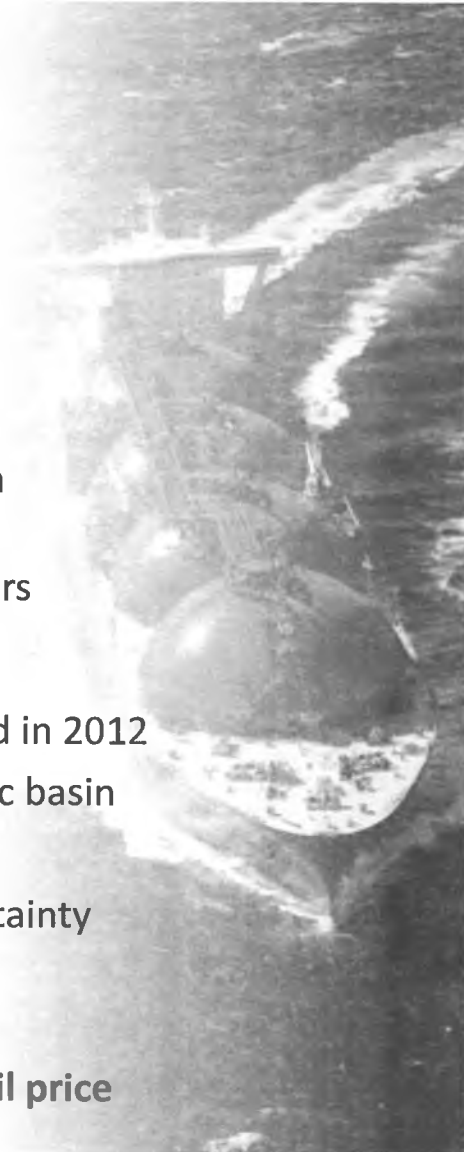
- Highly concentrated – 7 countries account for **70%** of demand
- Asia Pacific accounts for **70%** of global trade
- Growing rapidly – **8%** per annum over the past 5 years

Supply

- LNG Supply is also highly **concentrated** – 8 exporting countries provided **83%** of global LNG exports in **2012**
- Liquefaction capacity is rarely developed on a speculative basis
 - Liquefaction facilities typically cost **US\$5-20bn**
 - LNG facilities are generally **project financed**, requiring firm revenue commitments
 - LNG **specifications** vary by each project and between buyers

Contracts/ pricing

- Dominated by long term contracts (**LTCs**)
 - **~75% of global trade** was delivered under LTCs in 2011 and in 2012
 - Trade in Pacific basin is driven by LTCs more than in Atlantic basin
- **No liquid market** to provide price markers for LNG
- Price structure needs to give buyers and sellers reasonable certainty **over 20 years**
- Oil/oil product price linkage has been standard since the 1970s
- This link is usually defined in form of a **formula with slope to oil price and constant**



RECENT MARKET DYNAMICS: SUMMARY

Crude linked contracts

- Crude linked contracts are signed by **most suppliers** excluding North American export terminals
 - **Between 2002-2006**, some **low price contracts** were signed by China/Japan
 - **From 2007**, most recent contracts signed have a **14% - 15 % effective slope** for the relationship of LNG price (\$/Mcf) to crude price (\$/Bbl)

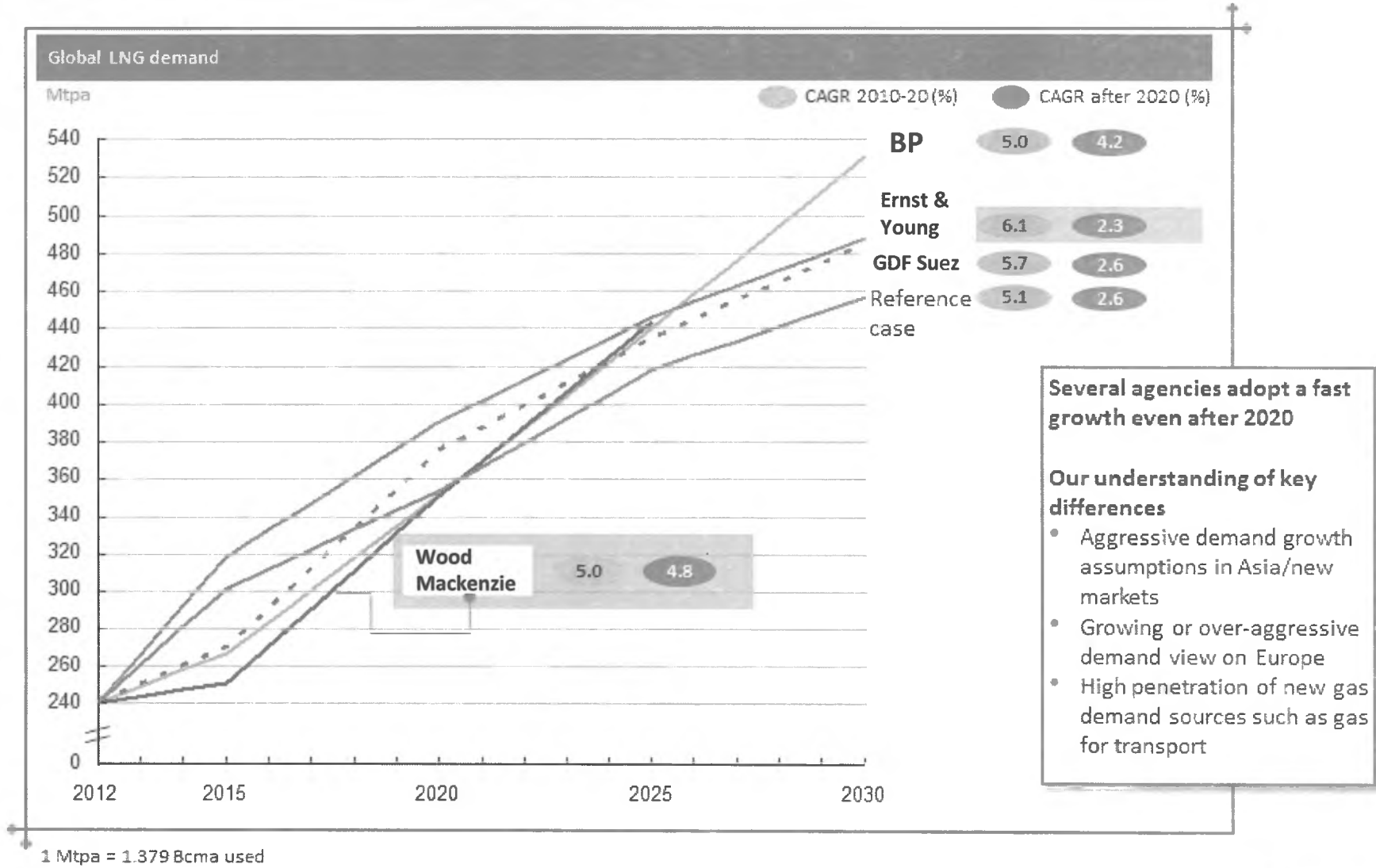
U.S. export contracts

- Emergence of **Henry Hub linked US LNG tolling** agreements has created an alternative to traditional crude linked contracts
 - **Delivered LNG prices** under these are currently **lower** than oil-linked contract prices
 - Buyers in countries such as **Japan** are **increasingly asking for these** and holding back on traditional contracts

Non price features/ players' responses

- Apart from pricing, **duration of contracts**, the **nature of commitment**, **delivery terms** and **LNG specifications** are important features to be considered
- Participants respond to **supply and demand changes** in a number of ways to **protect the price floor**

OUTLOOK FOR LNG DEMAND GROWTH VARIES ACROSS FORECASTING AGENCIES

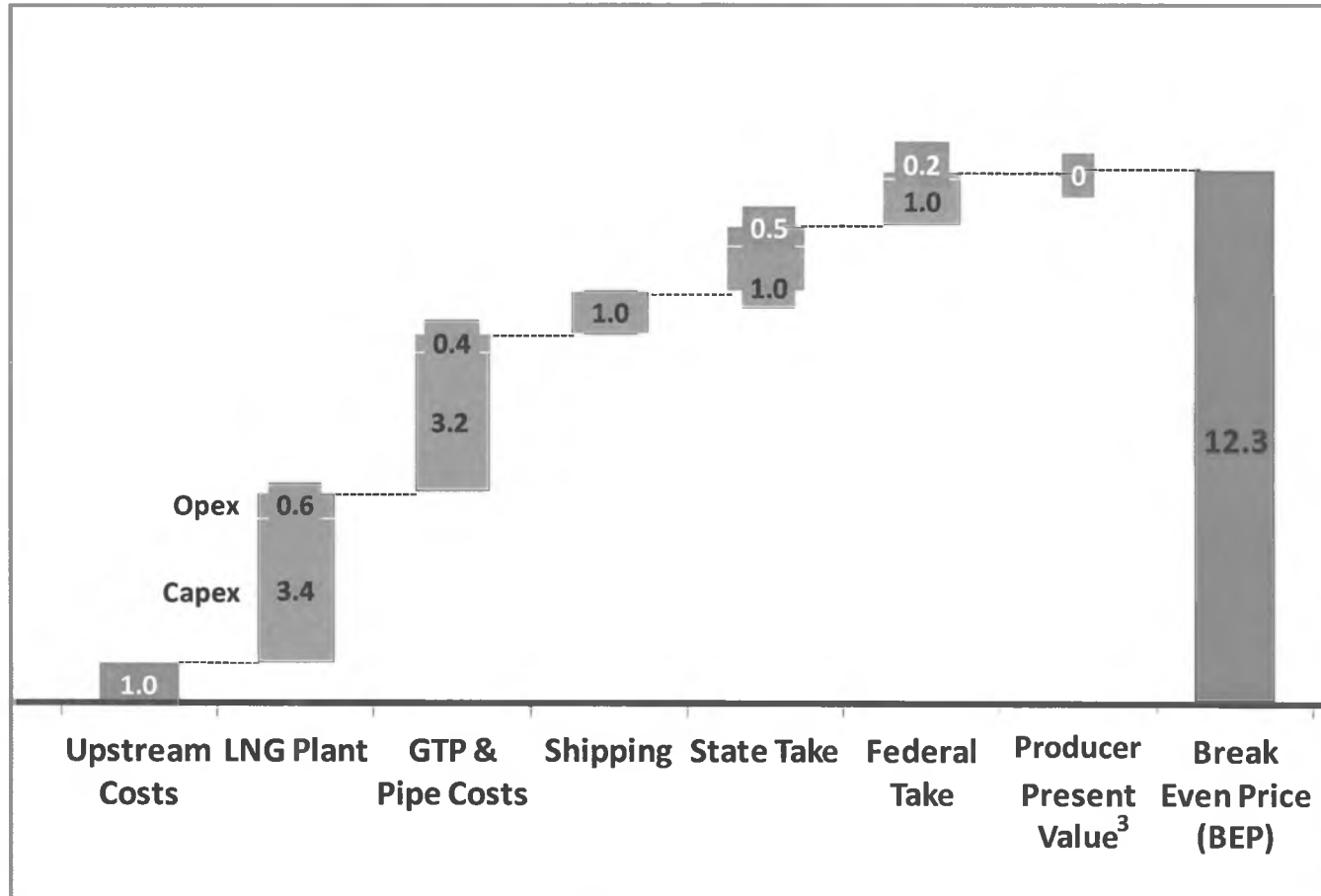


SOURCE: Public reports from or referenced information sourced from Wood Mackenzie; EY; BP; GDF Suez

AKLNG: PRESENT VALUE SHARE OF BREAK EVEN PRICE (ZERO NPV FOR PRODUCERS)

■ Upstream
■ Mid-stream

(2013 real US\$/MMBtu), LNG price delivered ex ship (DES) in Asia



Factors Impacting Break-even Price:
 US\$12.3/MMBtu is a conservative estimate subject to sensitivities

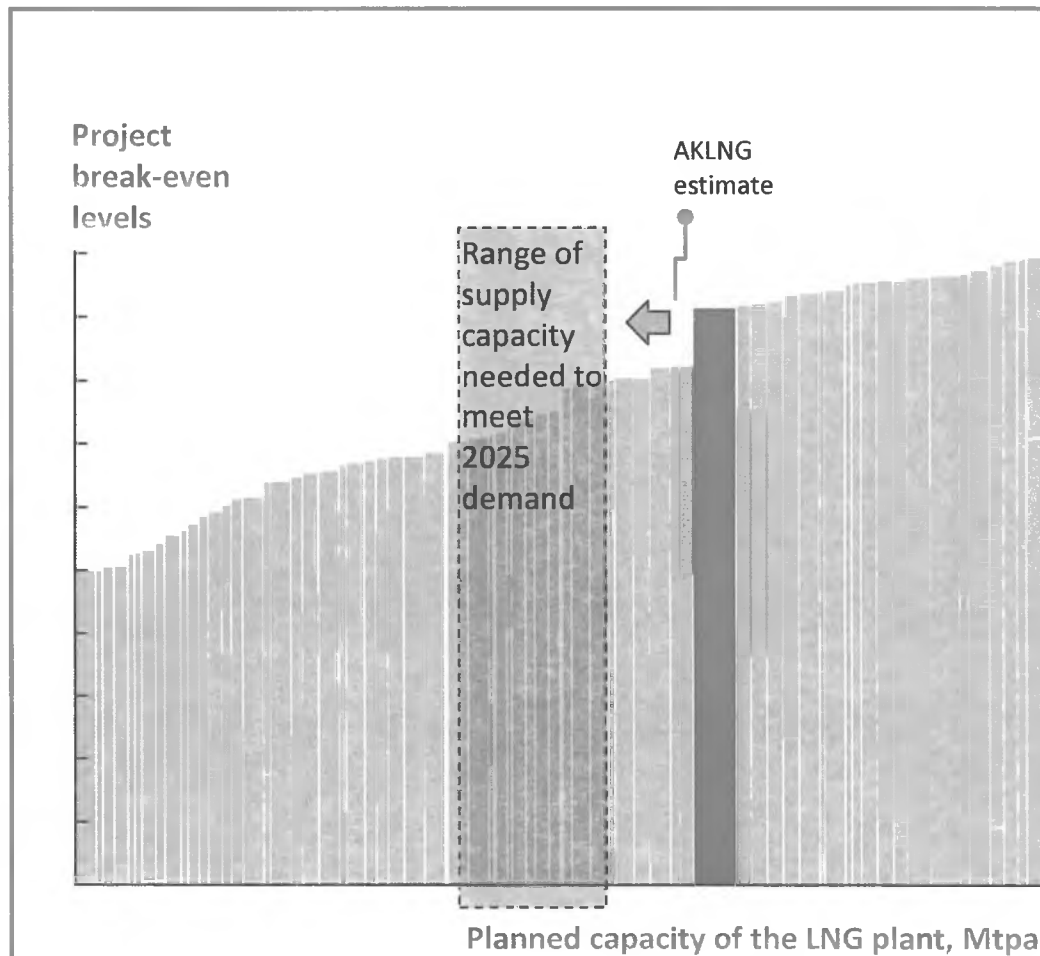
- Can increase the BEP:
 - Lower ambient temperature advantage (currently assumed 3.0 Mtpa²)
 - Negative effect of reduced oil production (currently excluded)
 - Capex increase, labor cost increase
- Can decrease the BEP
 - Capital productivity
 - Lower returns

¹ Discount rate used to calculate present value is 8.5% for mid-stream and 10% for upstream

² Effective ~17.4 Mtpa LNG capacity due to geographic advantage in Alaska

³ Assumes contractor would take on a project where revenue matches its costs, including expected return on equity

ON THE GLOBAL SUPPLY CURVE, AKLNG APPEARS TO CURRENTLY BE OUT OF THE MONEY, MODIFICATIONS REQUIRED FOR COMPETITIVENESS



ILLUSTRATIVE CHART, ANALYSIS DONE FOR ALL PROJECTS WITH STARTUP AFTER 2013

IMPLICATIONS:

- 1 AKLNG is currently out of the money:
 - Alaska break-even price is US\$12.3/MMBtu
 - Projects more economic than Alaska can provide ~340 MTPA new supply, more than required to meet global LNG demand (~250 – 300 MTPA)
- 2 AKLNG faces significant competition
 - There are several projects to the right in supply stack which will compete with AKLNG
- 3 However, the risk levels of competing LNG projects also needs to be considered
 - Due to political, resource and other risks, some in the money projects may be delayed/cancelled, leading to range of needed capacity

¹ NPV=0 @ discounted at Weighted Average Cost of Capital

SOURCE: Team Analysis

IN THE LONG RUN THROUGH 2030, LNG MARKET CAN EVOLVE WITHIN A BROAD RANGE



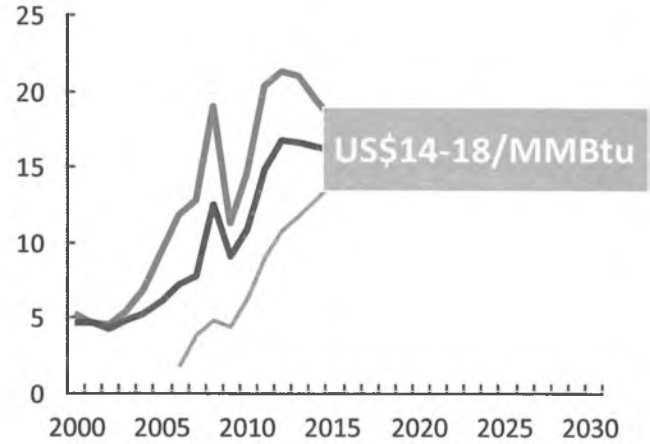
CASE

FACTORS AFFECTING

POSSIBLE PRICE RANGE

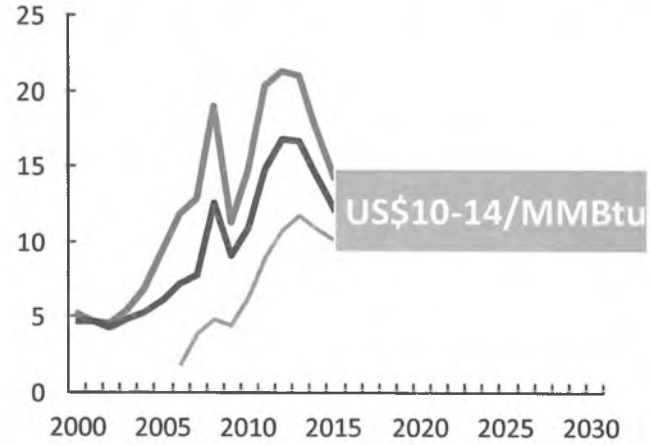
HIGH CASE

- North American LNG exports permitted at slow pace
- Non-NA Conventional supplies compete to serve the remaining demand
- Asian demand grows more rapidly than expected
- High cost LNG projects in Australia and Russia are the marginal supplies
- Sellers continue to demand high slope oil-linked contract terms



LOW CASE

- North American LNG supply is unconstrained and can meet all uncontracted demand
- Low cost non-NA conventional supplies compete directly with North American exports
- Henry Hub linked US exports become the price setter for Asian LNG



SUMMARY: LNG MARKETS

- 1** The LNG market is characterized by capital intensive projects and long-term contracts across the supply chain
- 2** The LNG market is illiquid and opaque, with few players, in contrast with the liquid and transparent oil market
- 3** LNG demand is expected to grow quickly over the short and long-term, but supply sources are also rapidly expanding
- 4** AKLNG appears to be out of the money within the global LNG supply curve under the status quo; cost and /or fiscal modifications could enhance competitiveness



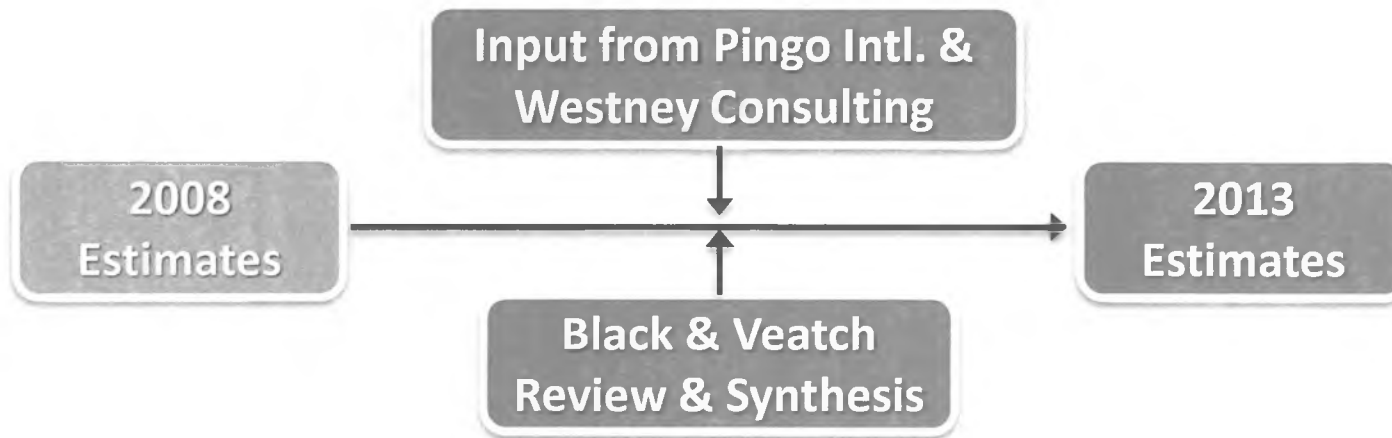
SUPPLY CHAIN ELEMENTS – SCOPE



- LNG Markets
- Supply Chain Elements
- Fiscal Framework
- Risk Allocation & Fiscal Structure

- Overview of the current capital cost estimates for the AKLNG Project
- Review of the capital structures that are likely to be applicable to AKLNG Project
- Discussion and assessment of applicable commercial structures for AKLNG Project

PROJECT CAPITAL COSTS UPDATE INCREASES BASELINE AKLNG PROJECT COST TO \$45 BILLION (2013\$)



Supply Chain Element	2008 Estimate ¹	2013 Updates	
		State's Estimate	Producers Estimate
GTP	\$5 Billion	\$10 Billion	\$10 - \$15 Billion
Pipeline	\$8 Billion	\$12 Billion	\$10 - \$15 Billion
LNG	\$14 Billion	\$23 Billion	\$17 - \$24 Billion
Total	\$27 Billion	\$45 Billion	\$37 - \$54 Billion

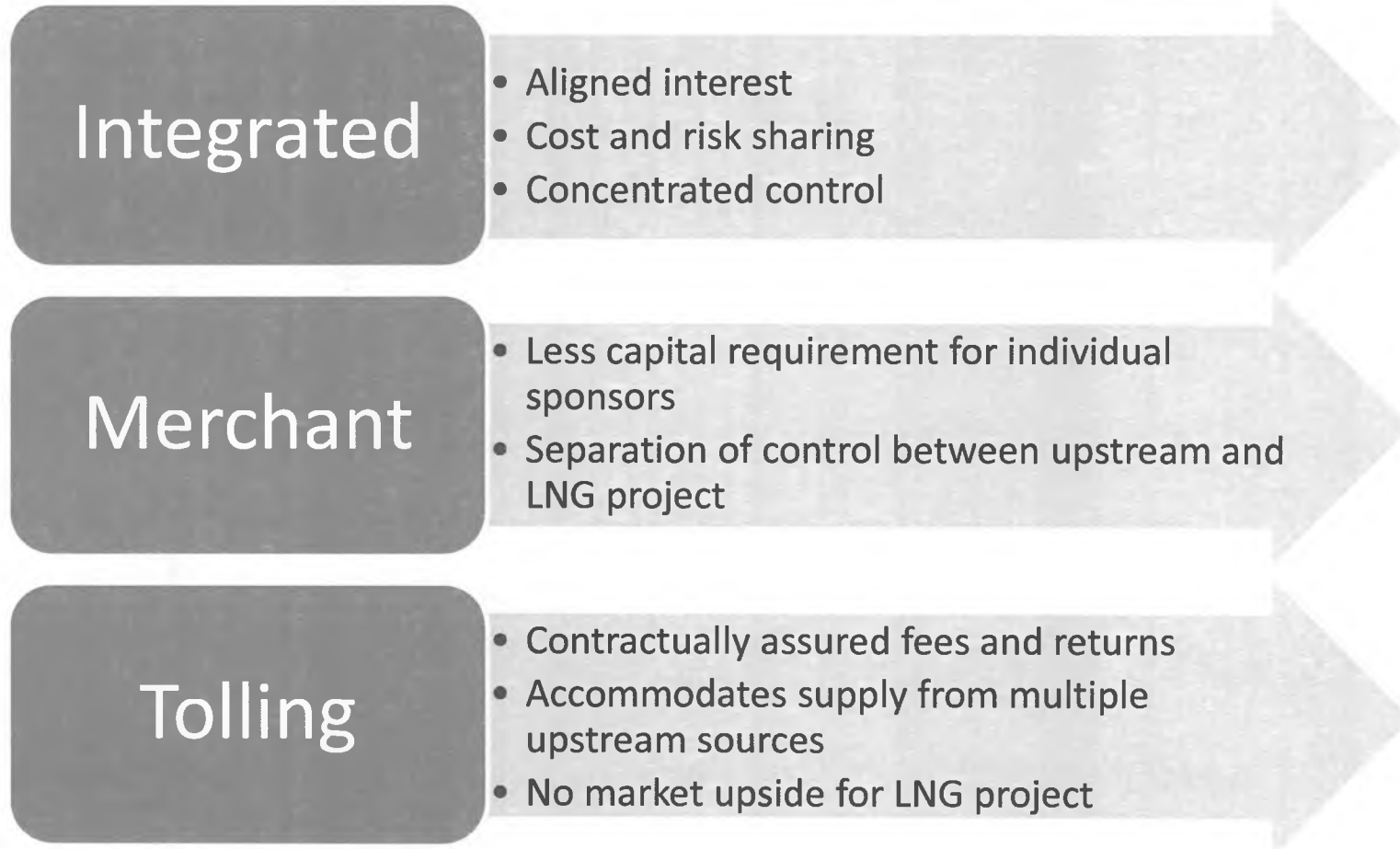
¹ Capital cost for a 2.7Bcf/d LNG project estimated by the State's Technical Team during AGIA proceedings.

CAPITAL STRUCTURES VARY FROM PROJECT TO PROJECT DEPENDING ON RISK PROFILE AND PARTNER PREFERENCES

	Partners	Capital Structure (Debt/Equity)	Comments
PNGLNG	ExxonMobil Oil Search Santos National Petroleum Company of PNG Nippon Oil MRDC	70/30	<p>Located at Caution Bay near Port Moresby, Papua New Guinea LNG is expected to have a capacity of 6.9 Mtpa and begin operations in 2014.</p> <p>PNGLNG is an integrated project and was the beneficiary of \$8.3 billion in loans and guarantees from public export credit agencies.</p>
APLNG	Origin ConocoPhillips Sinopec	70/30	<p>Two train design with a capacity of 9.0 Mtpa and requiring an investment of \$23 billion, Australia Pacific LNG. Train 1 financed \$8.5 billion.</p> <p>Origin operates the upstream segment of the project; ConocoPhillips operates the LNG facility.</p>
Gorgon LNG	Chevron Shell ExxonMobil Chubu Osaka Gas Tokyo Gas	0/100	<p>Gorgon LNG is the world's largest capital investment in an integrated LNG project. The \$53 billion 15 mtpa project is currently under construction and first LNG is expected in 2015.</p> <p>The project is financed through equity contributions from the partners.</p>
Qatargas 2	Qatar Petroleum ExxonMobil	70/30	<p>Qatargas 2 Train 1 produces 7.8 Mtpa , Total is a partner in the second train, which also produces 7.8 Mtpa</p>

The Debt / equity ratio that the market can support for a given project is driven by the financial strength of the partners

COMMERCIAL STRUCTURE OF PROJECT INFLUENCES RISK AND CONTROL



Each structure affects the operations and financing costs of the GTP, pipeline, LNG plant, and the shipper and impacts key criteria important to State - Commercial viability of AKLNG project, open access, expandability, transparency across the supply chain

KEY CHARACTERISTICS OF LNG PROJECT STRUCTURES

Structure	Advantages	Disadvantages
Integrated	<ul style="list-style-type: none"> • Equity owners may or may not act together to sell the LNG product from an integrated structure • Control over production • Aligned interests between owners • Cost sharing and potential tax benefits 	<ul style="list-style-type: none"> • Capital requirements are high and span the supply chain • Concentrated control makes expansions and entry of new participants difficult
Merchant	<ul style="list-style-type: none"> • Lower capital requirement if sponsors of upstream and LNG Project Co are different • Meets tax requirements for separate P&L center • Comply with local laws for government ownership of upstream project • Less control by upstream participants over liquefaction facilities 	<ul style="list-style-type: none"> • Less flexibility for equity participants in production of gas and selling LNG – sold uniformly by LNG Project Co • Commodity price risk exposure for LNG Project Co • Can be mitigated with variations of the merchant model, for example, by selling LNG back to project owners' marketing affiliate to insulate the project from risk • Exposure to negotiating power of upstream owners
Tolling	<ul style="list-style-type: none"> • Contractually assured fees and returns <ul style="list-style-type: none"> — Low market risk to LNG Plant Co — Mitigates upstream supply risk for LNG Plant Co • Potential tax benefits if title transfers are taxed • Accommodates supply from multiple sources, entities • Ability to attract other investors/owners to project – lower capital requirements • Facilitates project financing since liquefaction project revenues are not directly exposed to market risks 	<ul style="list-style-type: none"> • No participation in market upside for LNG Plant Co

State does not participate in upstream

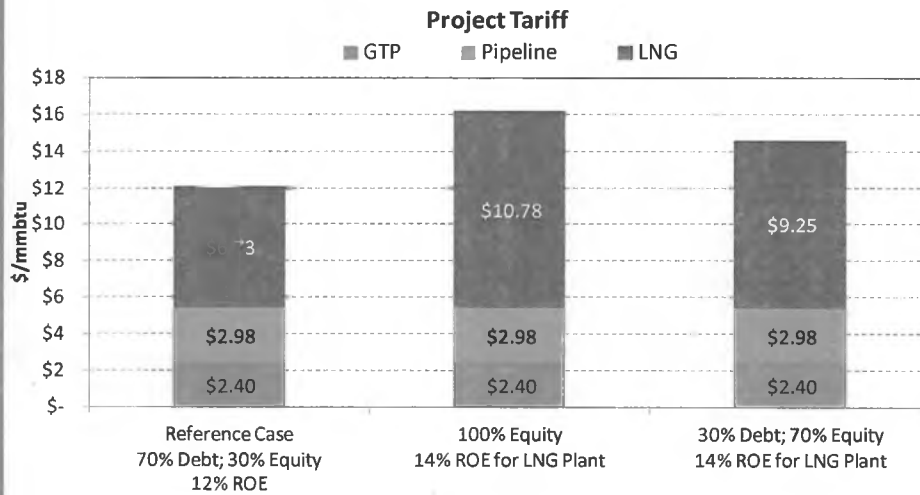


COMMERCIAL STRUCTURE OF AKLNG PROJECT COULD DRIVE MISALIGNMENT BETWEEN THE STATE AND PRODUCERS

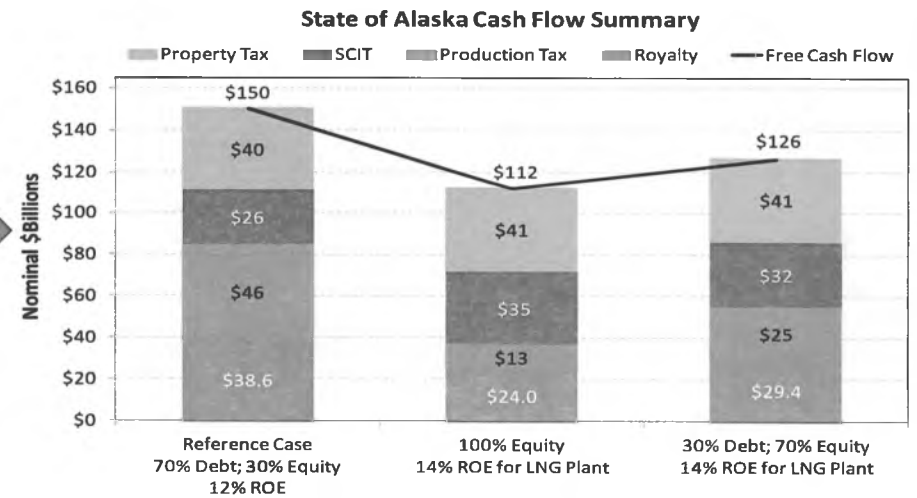
- A Producer-owned project creates risk for the State related to its fiscal revenues due to potential misalignment of interests between
- Under various alternate project structures contemplated, there could be incentive for Producers to shift revenues between the upstream and the midstream segment of the project, as a way of increasing Producer take (and thereby reducing the State's take) from the project
- This analysis examines a scenario where the LNG plant's service rates are established using an equity-rich financing structure and with a relatively high return on equity

IT IS CRITICAL TO CREATE ALIGNMENT BETWEEN STATE AND PRODUCER INTERESTS TO ENABLE STATE RECEIVING ITS FULL SHARE OF VALUE FROM THE AKLNG PROJECT

Equity-rich financing structure drives a high tariff for LNG Plant



State could lose billions of dollars of value through misalignment



- **Although the State could use regulations as potential safeguards, there is potential for misalignment of interests between the Producers and the State in a producer owned project**
 - Areas of potential misalignment include need for transparency, open access and low tariffs
- **Transparency within a producer-owned project into costs and cost allocation is likely to be an ongoing challenge for the State**
- **Creating alignment between the State and Producers is critical for the State to receive the full value of the AKLNG project**

SUMMARY: SUPPLY CHAIN ELEMENTS

- 1** Capital costs for AKLNG project are likely to remain uncertain through the development of the project
- 2** Total midstream project cost estimates from the AKLNG project sponsors range from \$37-\$54 billion
- 3** Complex LNG projects typically have an integrated commercial structure to give sponsors maximum control
- 4** AKLNG is expected to have an integrated structure; ensuring alignment of interests between the State and Producers is challenging and critical with a Producer-owned integrated project



FISCAL FRAMEWORK – SCOPE

- LNG Markets
- Supply Chain Elements
- Fiscal Framework
- Risk Allocation & Fiscal Structure



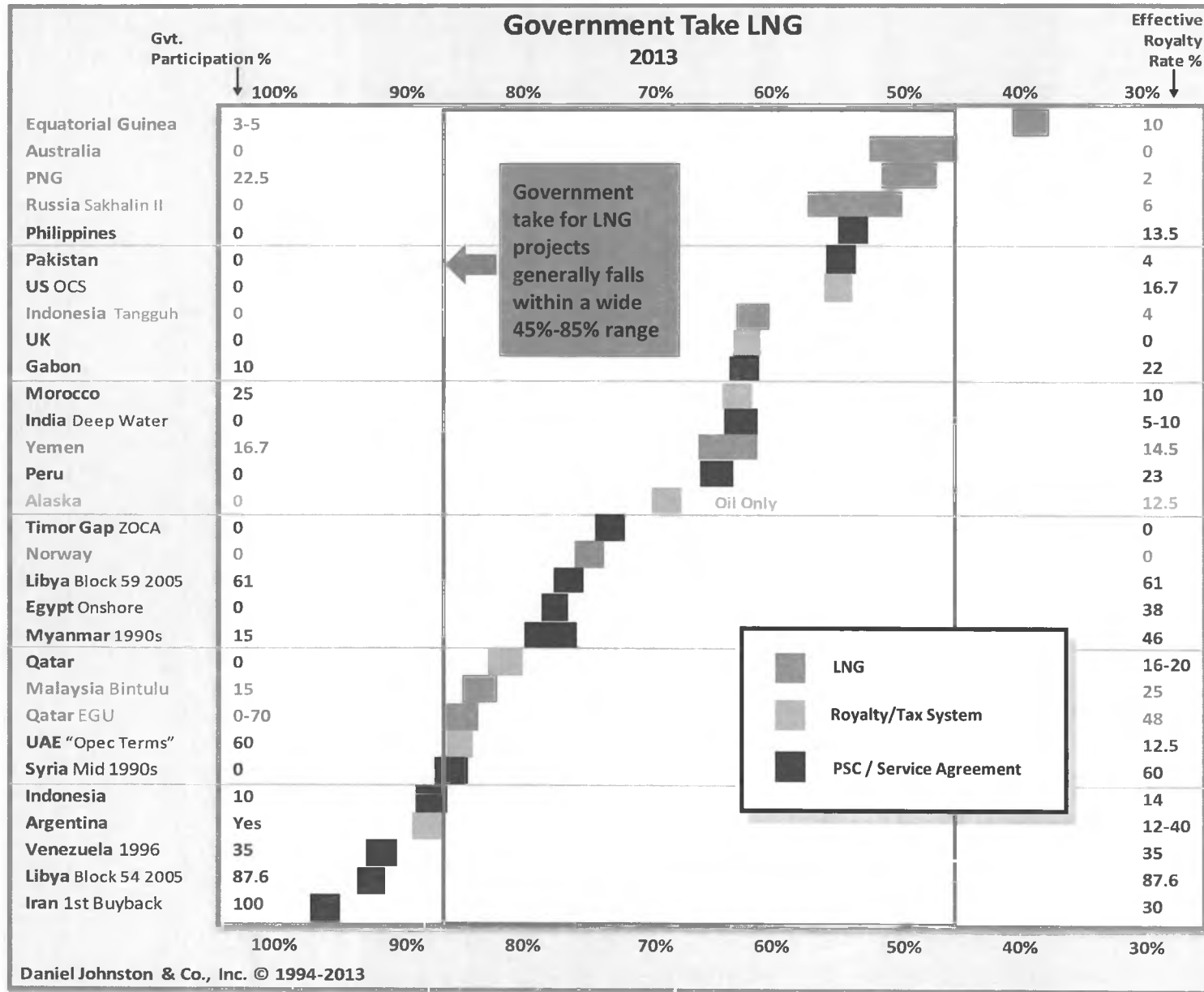
- Overview of the fiscal structures relevant to LNG projects worldwide and comparison with AKLNG Project
- Discussion and analysis of incentives that State could provide to help facilitate the AKLNG Project
- Assessment of how Alaska can leverage its royalty ownership position – royalty in kind relative to royalty in value

THREE MAIN FISCAL SYSTEMS ARE IN USE FOR OIL AND GAS AROUND THE WORLD

Fiscal system	Simple description	Examples
<p>Concessionary systems</p> <p>1 Tax-Royalty</p>	<ul style="list-style-type: none"> Title to the hydrocarbons transfers to the company at the wellhead. The host government receives royalties (% of revenues or production) and taxes (% of profits) from the company. 	<ul style="list-style-type: none"> U.K. U.S. Norway Australia Russia Canada
<p>Petroleum fiscal arrangements</p> <p>2 Production Sharing Contract</p>	<ul style="list-style-type: none"> Title to hydrocarbons resides with host government Production in kind is shared between the contractor and the government at the export point <ul style="list-style-type: none"> – A basic PSC has royalty, cost oil, profit oil and taxes 	<ul style="list-style-type: none"> Nigeria Angola Russia Algeria Kazakhstan Indonesia Qatar
<p>Contractual systems</p> <p>3 Service contracts</p>	<ul style="list-style-type: none"> Title to hydrocarbons resides with host government The contractor is reimbursed and paid a fee, typically in cash. These are rare and unpopular 	<ul style="list-style-type: none"> Iran Iraq Mexico Ecuador Russia

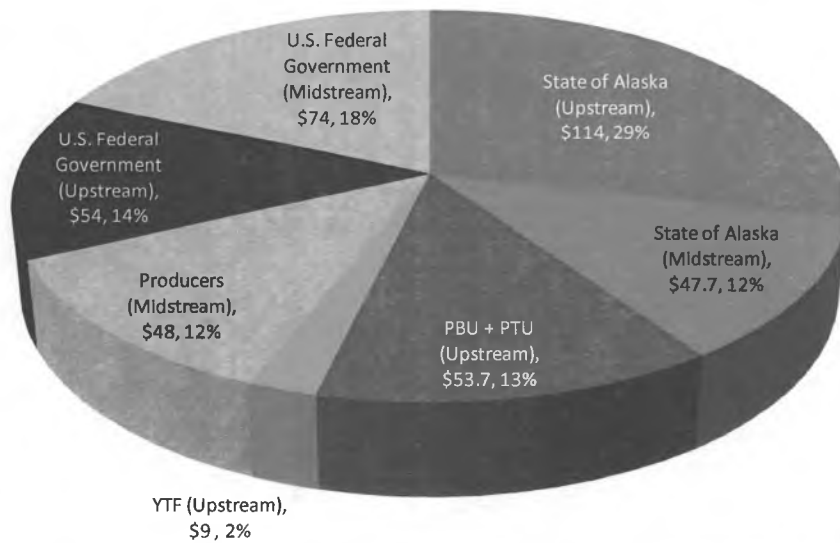
SOURCE: Team Analysis

GOVERNMENT TAKE ON LNG PROJECTS, BY COUNTRY



GOVERNMENT TAKE IN ALASKA IS BETWEEN 70%-80% UNDER SB21/MAPA FISCAL STRUCTURE WITH SIGNIFICANT FEDERAL GOVERNMENT SHARE

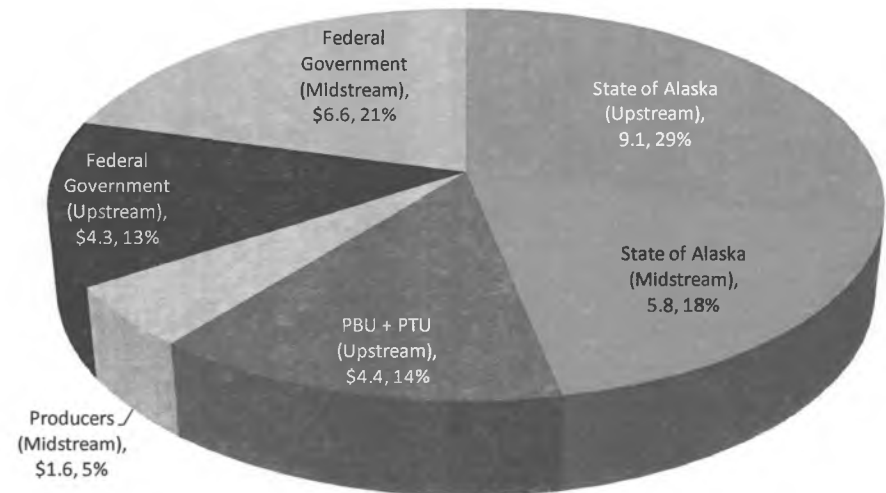
Gasline Impact Total Cash Flow by Stakeholder (Billions)



~\$400 Billion in Total Cash Flow

72% Government Share

Gasline Impact NPV₁₀ by Stakeholder (Billions)



~\$32 Billion in Total NPV

81% Government Share

* Negative NPV for YTF Fields of \$-0.1B not shown

With current levies alone, government take is significant in the context of LNG projects worldwide

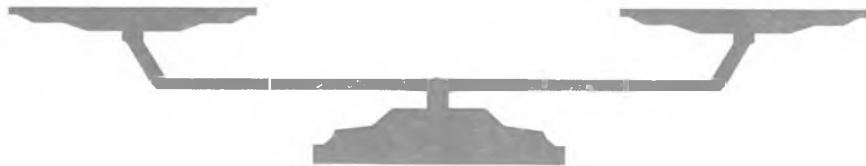
IMPACT OF FISCAL LEVERS UNDER DIFFERENT PRICE AND CAPEX MARKET CONDITIONS - NPV₁₀ (\$2013 BILLIONS)



- The analysis demonstrates that market prices dominate the AKLNG project's economics dwarfing all other variables considered
- Royalty, property tax and production tax reductions are beneficial in improving Producer NPVs and IRRs from the project and reducing State take.
- Overall government take impacts are dampened because ~35% of value transferred from the State to Producers goes to the Federal Government through federal income taxes
- To the extent that the State provides incentive to the AKLNG project through a value transfer, alternate mechanisms that reduce the leakage of this value to the federal government could be more effective in benefitting the AKLNG project

ROYALTY IN KIND VS. ROYALTY IN VALUE

	Advantages	Disadvantages
Royalty In-Kind	<ul style="list-style-type: none"> • Attractive to producers • Reduces valuation disputes • Reduces commercial uncertainty for project • Provides the State with better market insight 	<ul style="list-style-type: none"> • Exposes State to various additional risks • Requires modifications to current legislation and authority • Requires marketing expertise • Credit requirements for shipper agreements
Royalty In-Value	<ul style="list-style-type: none"> • Status quo, familiarity • No direct firm capacity commitments • RIV auditing and management capabilities currently exist 	<ul style="list-style-type: none"> • Lack of transparency • No third party access (TPA) • Valuation disputes: higher of; actual market price realized • Gaming over cost deductions • Not preferred choice of producers

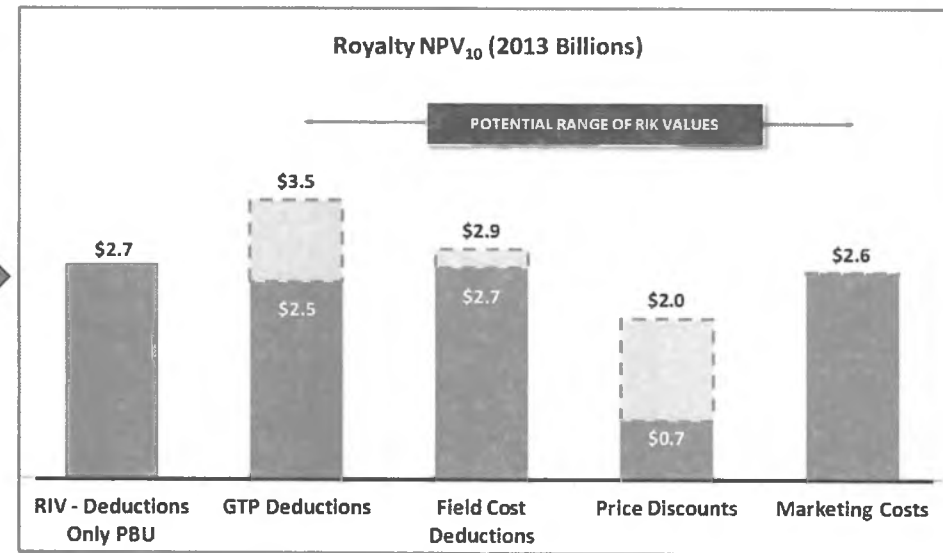


Note: Equity participation with or without In-Kind Gas is another alternative for the State to consider and has been addressed separately

IMPLEMENTING RIK PRESENTS CHALLENGES AND, HENCE, COSTS FOR THE STATE RELATIVE TO RIV

NPV losses to the State from going RIK could be as much as 75% of value relative to RIV

COST DRIVER	RIV	RIK
GTP Costs	Only PBU is currently allowed to deduct GTP costs for royalty calculation	GTP costs will likely be borne by State for all fields
Upstream Field Cost Allowance ("FCA")	PBU is currently allowed an Upstream FCA	Upstream FCA for all fields, potentially
Higher of Provision	Higher of provision creates price protection, offers ~3% uplift in royalty value	No higher of provision for price protection
Sales Price Discount	Theoretically, State achieves a portion of Producer's full value	State expected to suffer discounted prices due to market inexperience and lack of diversity of supply; Discount to LNG sales price of the LNG multiplier in the 1% to 3% range examined as range
Marketing Costs	No marketing costs, but audit costs	Marketing costs of \$7-\$15 million a year
Credit Costs	Credit cost borne by Producers	Borne by State



RIK CREATES ADDITIONAL RISK AND COST FOR THE STATE RELATIVE TO RIV

- **Taking its royalty in kind could potentially expose the State to significant risks including:**
 - The State may need to build its own marketing organization to take care of origination, logistics, contract administration, accounting, etc. if it chooses to market the gas
 - State would face challenges in competing with the Producers who have well established LNG marketing expertise and global portfolios
 - State would be subject to counterparty risk in all of the contracts it enters into across the LNG supply chain
 - State would need to make firm capacity commitments along the LNG supply chain, which could total up to \$1 billion per year
 - State could realize negative royalties if the LNG price is too low
 - State would face production volume risk (if production exceeds or falls short of its sales commitments)
- **Producers have the experience of dealing with market uncertainties and would need to help the State address these risks if an RIK path is pursued**

SUMMARY: ALASKA FISCAL FRAMEWORK

1

Government take, at 70-85%, is high for a project of this complexity, and estimated IRR of approximately 15% may be insufficient for Producer investment relative to their alternatives

2

Well designed incentives to lower project costs and modify fiscal structure can help make the AKLNG project competitive in market

3

The State taking its royalty as RIK could result in a substantial increase in risk & potential loss of value for the State – Producers have more experience managing associated risks



RISK ALLOCATION & COMMERCIAL STRUCTURE – SCOPE

- LNG Markets
- Supply Chain Elements
- Fiscal Framework
- Risk Allocation & Fiscal Structure

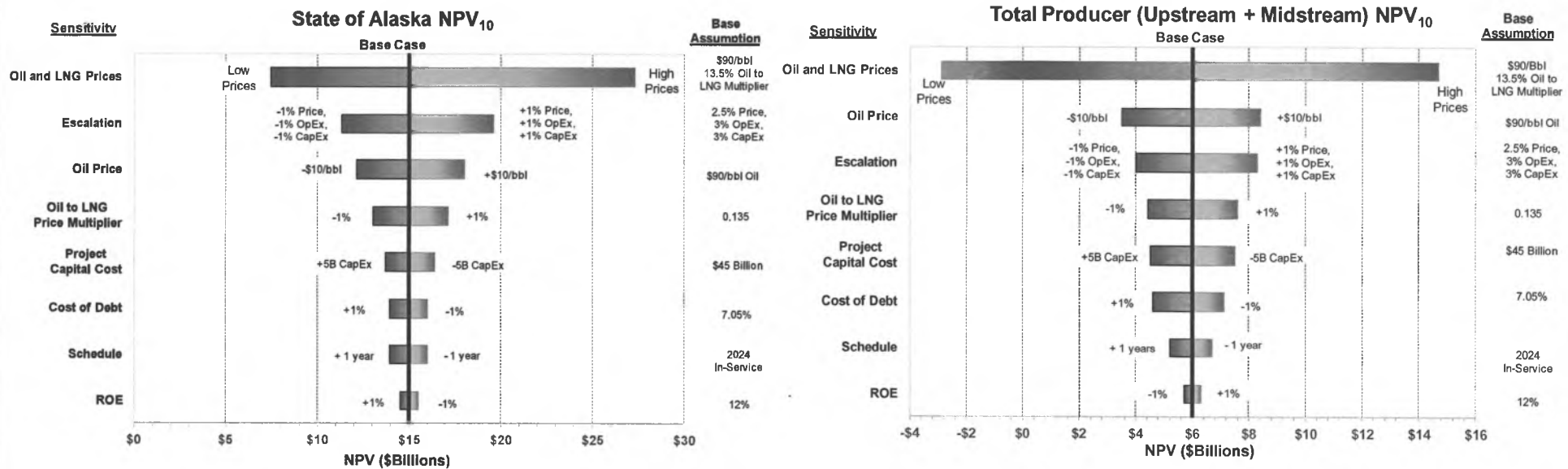


- Overview of key risks that could impact the AKLNG Project stakeholders and risk management
- Assessment of alternatives for financial, equity participation by State in AKLNG Project

THERE ARE VARIOUS UNCERTAINTIES RELATED TO THE AKLNG PROJECT THAT COULD IMPACT THE ECONOMIC BENEFITS TO THE DIFFERENT STAKEHOLDERS



PRICE AND CAPITAL COST RELATED UNCERTAINTIES EMERGE AS THE KEY FACTORS DRIVING THE PROJECT ECONOMICS



¹ Base Price = \$90/bbl oil price in \$2013; LNG Price per MMBtu = 0.135*Oil Price + \$1

High Price = \$120/bbl oil price in \$2013; LNG Price per MMBtu = 0.15*Oil Price + \$1

Low Price = \$60/bbl oil price in \$2013; Henry Hub Price = \$4/MMBtu in \$2013; LNG Price per MMBtu = HH+\$6

² The escalation sensitivity captures a variation in the assumption related to annual change in capital costs, operating costs and oil and gas prices

RISK ALLOCATION AND MANAGEMENT

Cases of risk allocation

- Cost and time risks in project execution depend on the nature and extent of project organization apart from market factors
 - Of the recent LNG projects, most have a **single operator** for upstream, transport and liquefaction
 - **Integrated project** case has been successful in **high cost project execution** (Snøhvit case example)

Cases of risk mitigation

- **Market risk management** is executed by LNG projects in two ways:
 - **Pre-FID commitments:** Majority of project volumes are contracted before FID to ensure market. Example: Gorgon, APLNG
 - **End user participation:** Several projects have equity stake of end buyers providing ensured-market for corresponding equity volumes. Example: Tangguh, Sakhalin II

State participation and implications

- Where the **Government participates** in LNG projects is usually via **NOCs** with LNG majors who bring in LNG project experience
- State's **equity participation** in the project can **allow state to capture an upside** in prices but exposes it **further to a down-side**
- Examples: Snøhvit, Yemen LNG, Angola LNG

EQUITY PARTICIPATION BY THE STATE OF ALASKA COULD HAVE TANGIBLE BENEFITS FOR THE PROJECT AS WELL AS THE STATE

- To the extent that the State transfers value to the Producers through a modification of fiscal terms as an incentive for the AKLNG project, **obtaining an equity interest in the project in exchange for that transfer of value** is more beneficial to the State than a simple reduction in fiscal take
- Greater **alignment of economic interests** between the State and Producers
- State ownership **lowers the upfront capital cost** to Producers creating potential economic uplift
- Allows for **TCPL equity participation** and operation of the pipeline and GTP
- Equity in all phases could facilitate greater **transparency in the AKLNG Project**
- Allows State to influence **access for third parties** in the most critical potential bottlenecks of the project – pipeline and marine terminal
- Equity investment in the supply chain, while allowing SOA a seat at the table, **does not necessarily provide for a vote in the decision making process**
- **Joint Venture Agreement structuring** is critical

ALTERNATIVES FOR THE STATE TO PARTICIPATE WITH AN EQUITY INVESTMENT IN THE AKLNG PROJECT – DESCRIPTION

Three different alternative structures for equity participation for the State were considered as indicative examples:



Equity Alternative

- The State makes an equity investment across the midstream and receives an equivalent share of gas produced as royalty and tax gas
- Two different equity investment levels were considered as representing lower and upper bounds on the State's equity participation – 15% and 35%



100% State Ownership of Pipeline

- The State invests sufficient equity to entirely own the pipeline component of the midstream
- Producers would pay a tariff to the State for transportation services on the pipeline

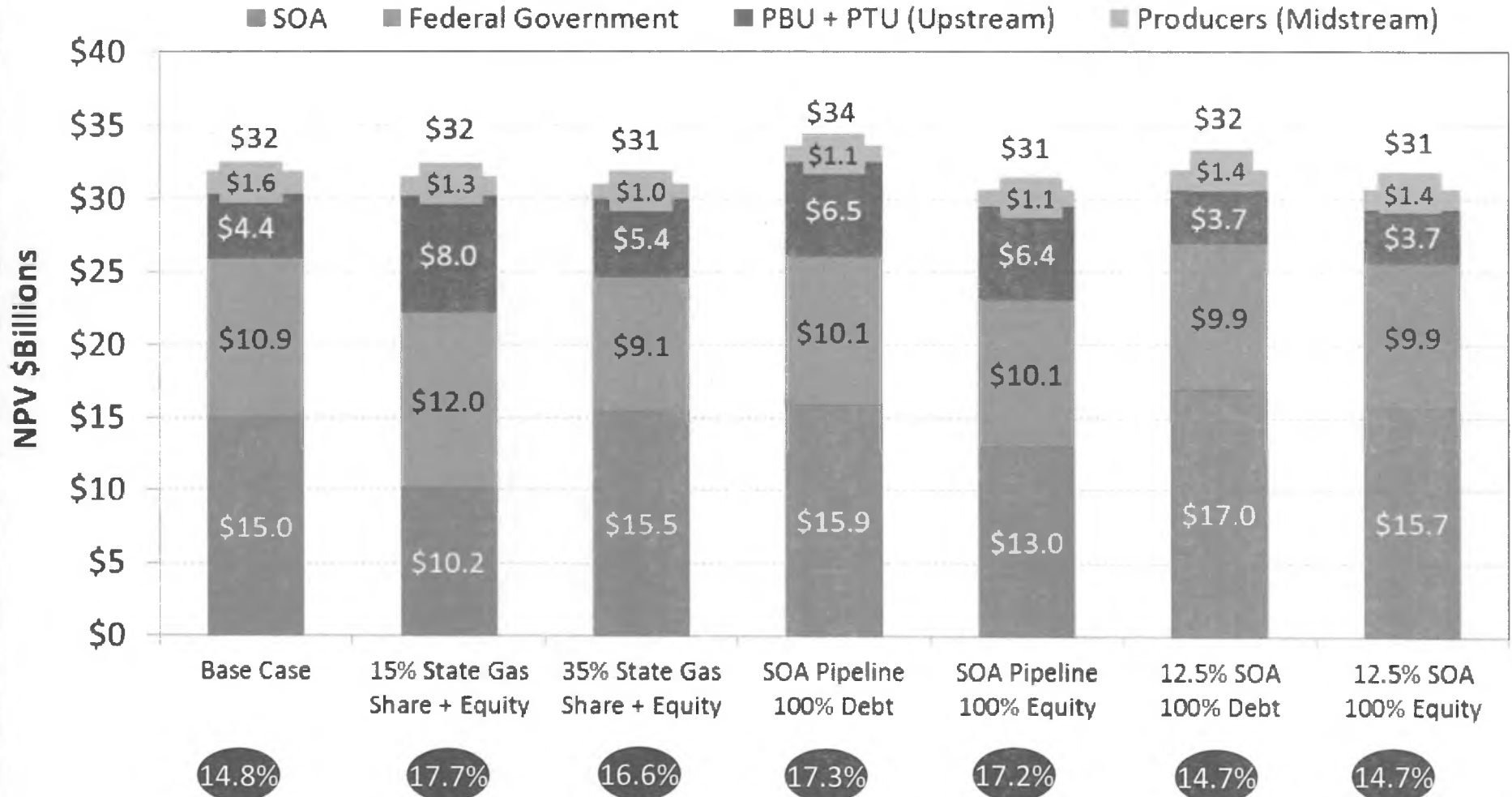


12.5% State Ownership of Midstream

- The State invests to have a 12.5% equity stake across the midstream corresponding to an approximation of its royalty share
- The State's share of the capacity would be utilized to treat, transport and liquefy royalty gas

STATE EQUITY PARTICIPATION AT APPROPRIATE LEVELS COULD ALLOW SOA AND PRODUCERS TO RETAIN HIGHER SHARE OF PROJECT REVENUES

Stakeholder NPV₁₀ Case Comparison



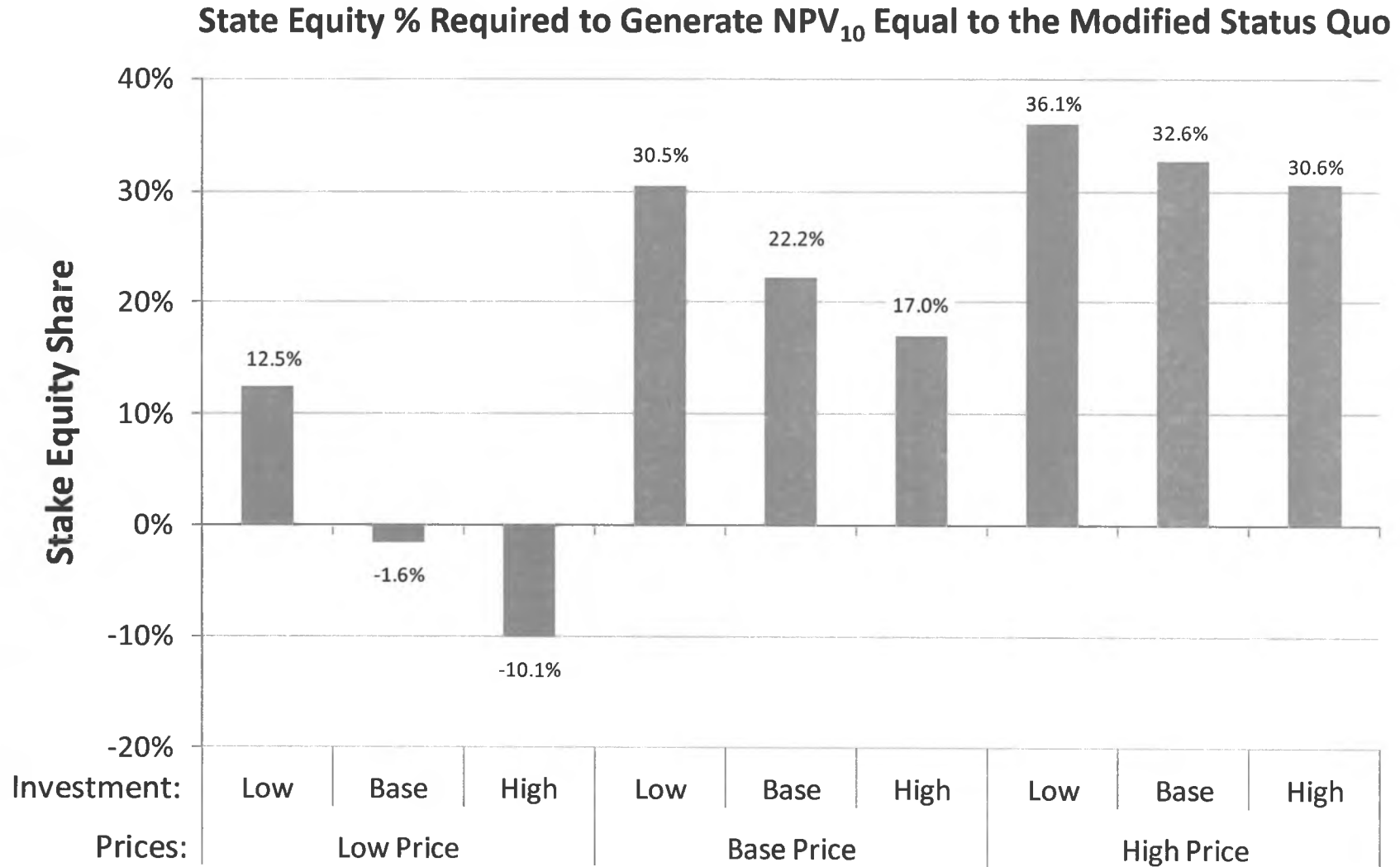
% Producer (Upstream + Midstream) IRR



APPROPRIATE LEVEL OF STATE EQUITY PARTICIPATION NEEDS TO BE BALANCED TO ACHIEVE BENEFITS TO SOA AND PRODUCERS

- **Scenarios examining a range of capital costs and market prices were assessed to understand whether the equity alternative provides positive economic value to the State relative to status quo under each of the scenarios**
- **15% and 35% state equity participation levels in combination with equivalent royalty gas & tax gas were considered as indicators of lower and upper bounds to the State's equity participation**
- **SB21/MAPA fiscal structure as currently applicable does not include production credits for gas. This analysis assumes a modified status quo wherein the production credits are extended to reflect a \$5/BOE credit for gas, similar to the credit extended to new oil production**
- **The analysis estimated and compared AKLNG project economics under modified status quo and under the equity alternative for both the State and the Producers across a combination of three price and three capital cost scenarios**

STATE EQUITY PARTICIPATION BETWEEN 20% AND 30% OFFERS NPV₁₀ AT OR ABOVE THE MODIFIED STATUS QUO LEVELS FOR THE STATE



The level of State equity investment required to equal total state NPV₁₀ under status quo varies with market conditions

SOA EQUITY INVESTMENT IN AKLNG CREATES RISK EXPOSURES THAT NEED TO BE CONSIDERED AND MANAGED

- **Cost overruns and cash calls above appropriation level**
- **As an equity owner, the State assumes all Force Majeure risk throughout the GTP, pipeline and LNG terminal**
- **State has no control over upstream operations and volumes produced by the Producers**
 - Could have excess or insufficient capacity relative to volumes produced
 - Balancing production volumes and volumes through the supply chain on a short-term and long-term basis
- **If the State assigns its equity position to a third party such as TransCanada and contracts for capacity with this third-party, the State will likely have to provide credit support to the entity that would assume the state's equity share in the midstream through long-term commitments for capacity**
- **State would be responsible for all demand charge obligations throughout the life of the contract regardless of gas supply availability and market conditions**
 - Possible that revenues earned on LNG sales would not offset costs of treating, transport and liquefaction resulting in negative cash flows to the State

SUMMARY: RISK ALLOCATION & COMMERCIAL STRUCTURE

- 1** AKLNG faces various risks that could affect the economic benefits; prices and capital cost are key
- 2** Direct equity participation by the State can offer benefits to all parties involved in the project; accompanying risk profile changes should be managed
- 3** Various commercial terms related to equity participation will determine whether the State can achieve its transparency and access objectives



BUILDING A
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FEBRUARY 10, 2014

SUPPLEMENTAL ANALYSIS – TRANSCANADA PARTICIPATION

PREPARED FOR THE STATE OF ALASKA



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BACKGROUND

- **As part of exploring an equity position in the Alaska LNG (“AKLNG”) Project, the State of Alaska (“the State” or “SOA”) is contemplating a commercial arrangement with TransCanada for the Midstream Component where the State:**
 - shifts initial project capital burden to TransCanada
 - secures favorable debt/equity ratio for transportation services
 - obtains benefit of TransCanada’s northern pipeline experience
- **As part of this commercial arrangement, TransCanada will fund development of the State’s share of the mid-stream assets during the pre-FEED stage and provide the State with an equity option to purchase an interest of up to 40% of this share prior to entering the FEED stage of the project. This means the State would receive up to 40% of the equity return TransCanada receives and be responsible for up to 40% of TransCanada’s cost during FEED and ultimately, construction and operation.**

KEY ASSUMPTIONS

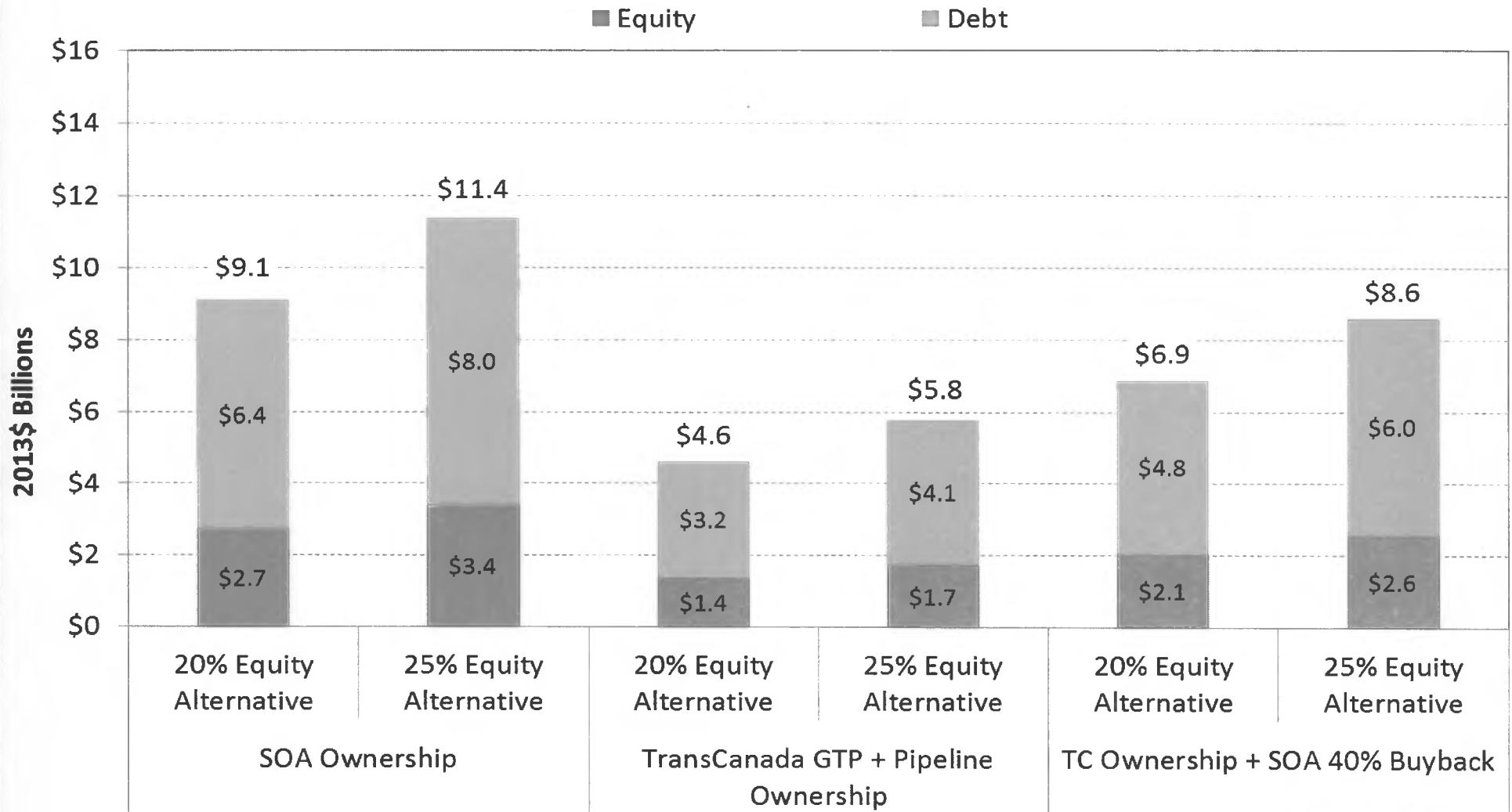
- **The purpose of this analysis is to evaluate the impact of TransCanada’s ownership in the AKLNG project on the State of Alaska**
- **This study analyzed two different alternate levels of State equity participation and State Gas Share – 20% and 25%**
- **Under each equity alternative case, three ownership scenarios were analyzed to determine whether there is benefit from TransCanada’s participation in the AKLNG project:**
 - SOA Ownership – State retains ownership in its 20%-25% share of the GTP and Pipeline
 - TransCanada GTP + Pipeline Ownership – TC assumes the State’s 20%-25% share of the GTP and Pipeline
 - TC Ownership + SOA 40% Buyback – TC assumes the State’s 20%-25% share of the GTP and Pipeline, but SOA exercises an option to buy back 40% ownership in these components at the beginning of the FEED stage of project development
 - In all three scenarios above, the State retains its 20%-25% share of the LNG Plant
- **Key terms proposed for TC’s services provided to the State include:**
 - Debt/Equity: 70/30 through first year of operation; 75/25 thereafter
 - Return on Equity: 12% plus rate tracker
 - Cost of Debt: 5% plus rate tracker
- **It is assumed that there is a 6% opportunity cost associated with any equity investment by the State (reflecting assumed returns from the Constitutional Budget Reserve Fund)**

TRANSCANADA PARTICIPATION – FINDINGS

- **TransCanada’s participation in the AKLNG project can reduce the State’s total investment in the Project by between \$2 billion and \$5.5 billion depending on the total equity stake ultimately owned by the State**
 - Assuming a 70/30 debt to equity ratio for the State, TransCanada’s participation in the AKLNG project can reduce the equity investment required from the State by between \$600 million and \$1.7 billion depending on the total equity stake
- **TransCanada’s involvement creates additional value of \$3-\$6 billion on a cash flow basis and between \$600 million and \$1 billion on an NPV basis for the State of Alaska through the initial 30 year project life**

STATE OF ALASKA TOTAL CAPITAL INVESTMENT (IN 2013\$)

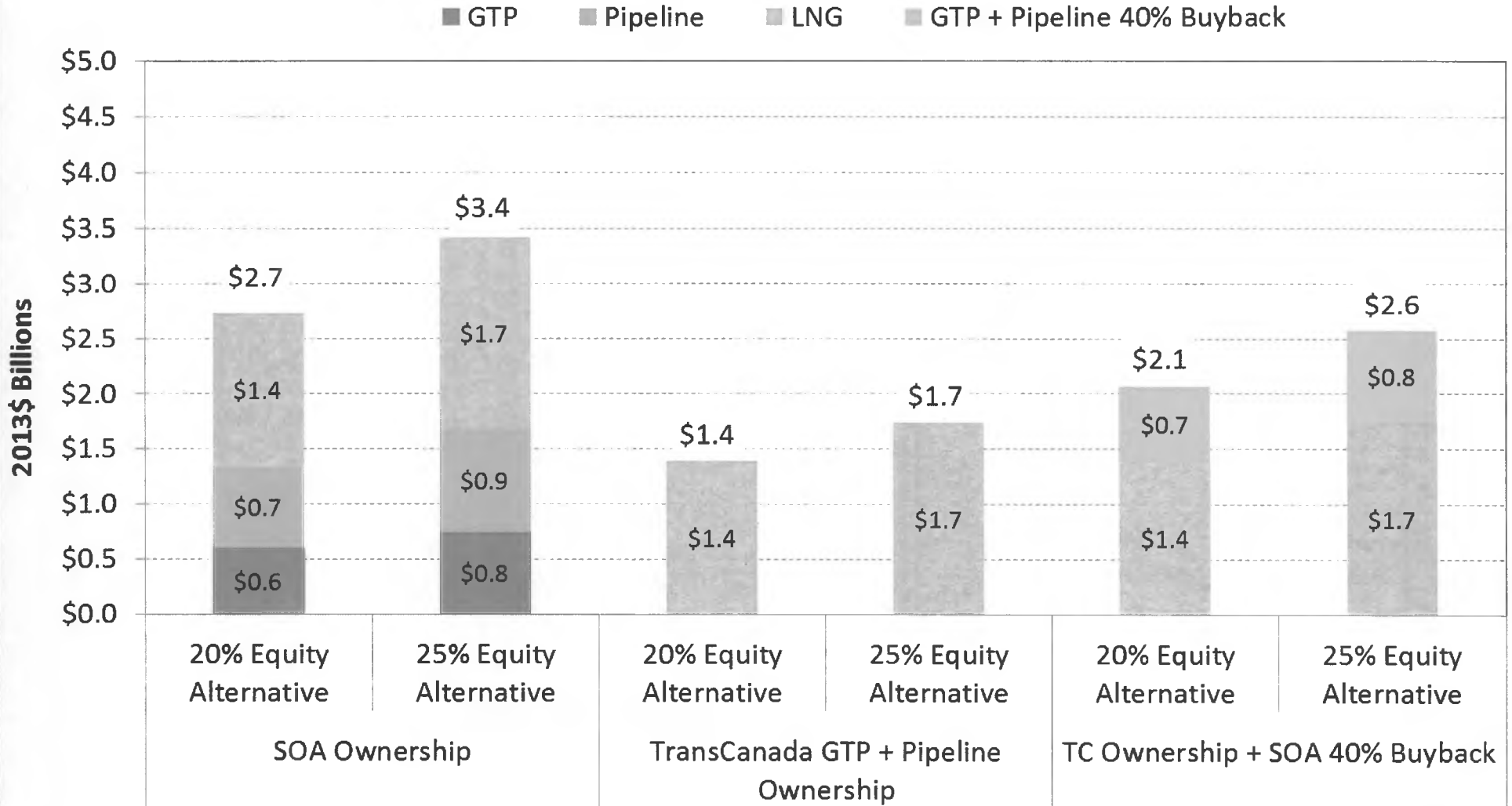
SOA Total CapEx in Real Dollars



DRAFT – SUBJECT TO REVISION

STATE OF ALASKA EQUITY CASH CALLS* (IN 2013\$)

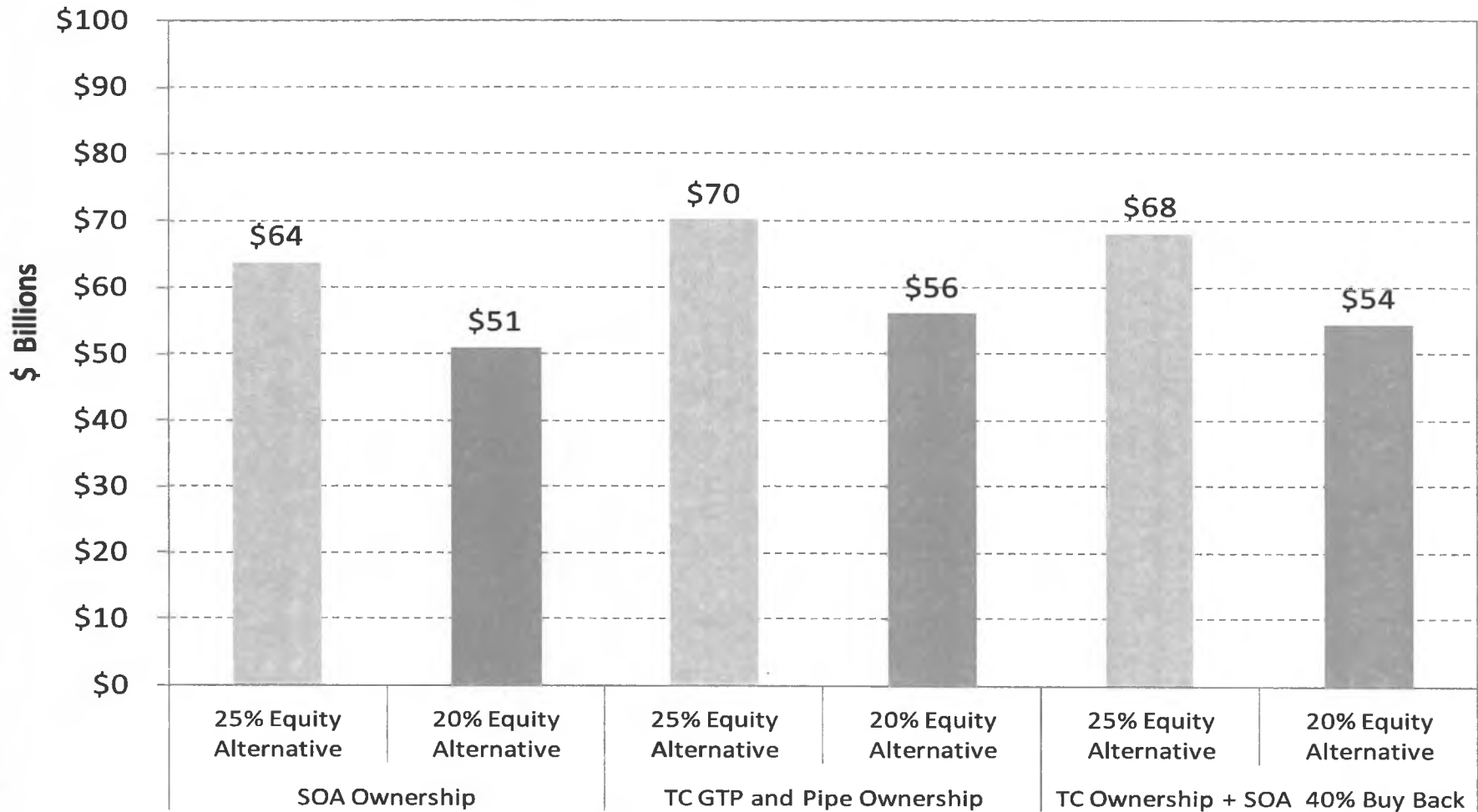
SOA Equity CapEx in Real Dollars



*Assumes a 70/30 debt/equity split for the State's investment

STATE OF ALASKA TOTAL CASH FLOWS ASSOCIATED WITH EQUITY ALTERNATIVE*

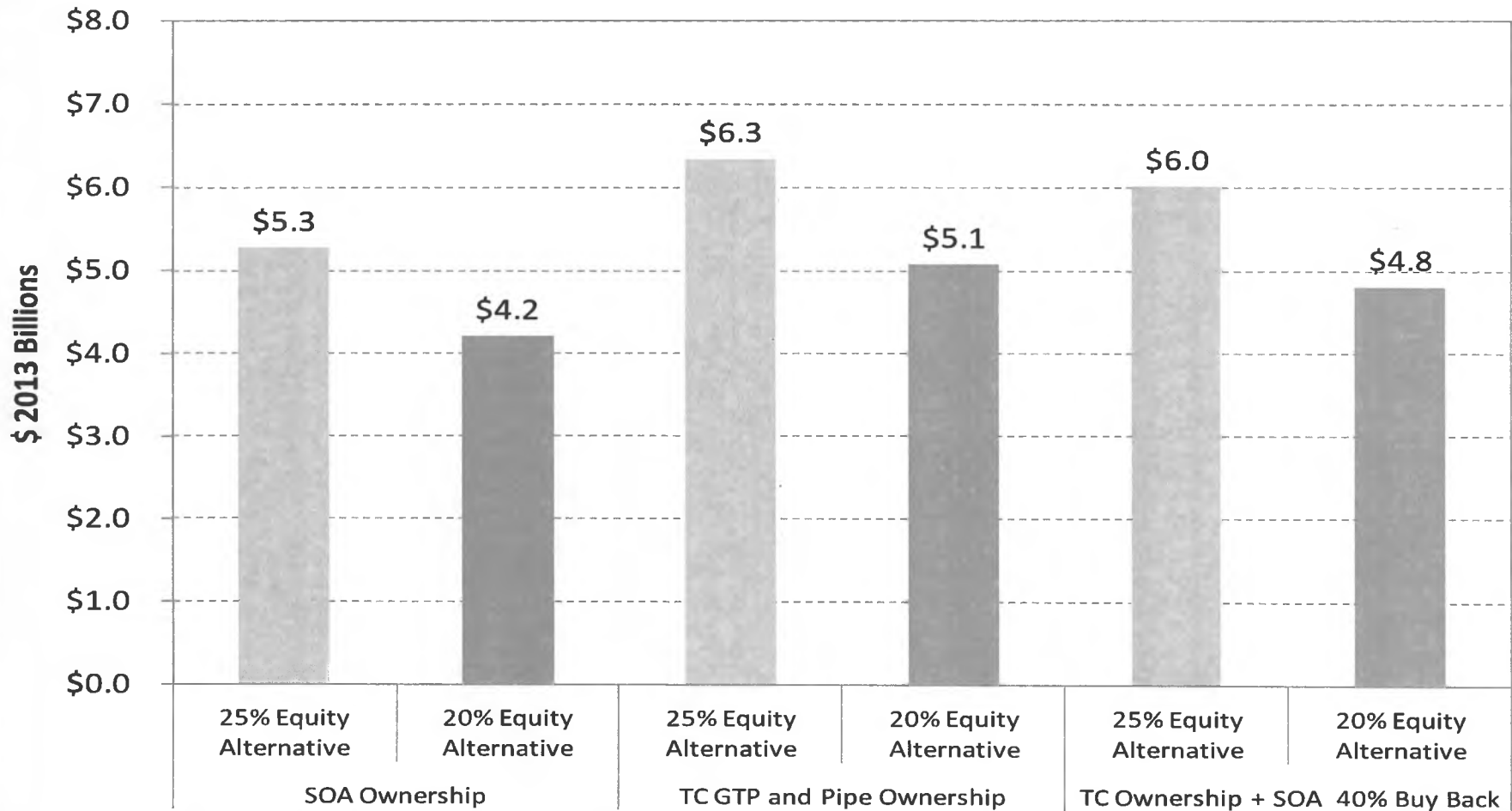
Total Cash Flows to State of Alaska Associated with Equity Alternative



* Includes cash flows over initial 30 years; Cash flows exclude additional revenues to the State from the AKLNG Project such as upstream property and income taxes that are not impacted by TC participation. Values include the estimated impact of opportunity cost to the State which may not be a cash flow element.

STATE OF ALASKA NPV₁₀ ASSOCIATED WITH EQUITY ALTERNATIVE*

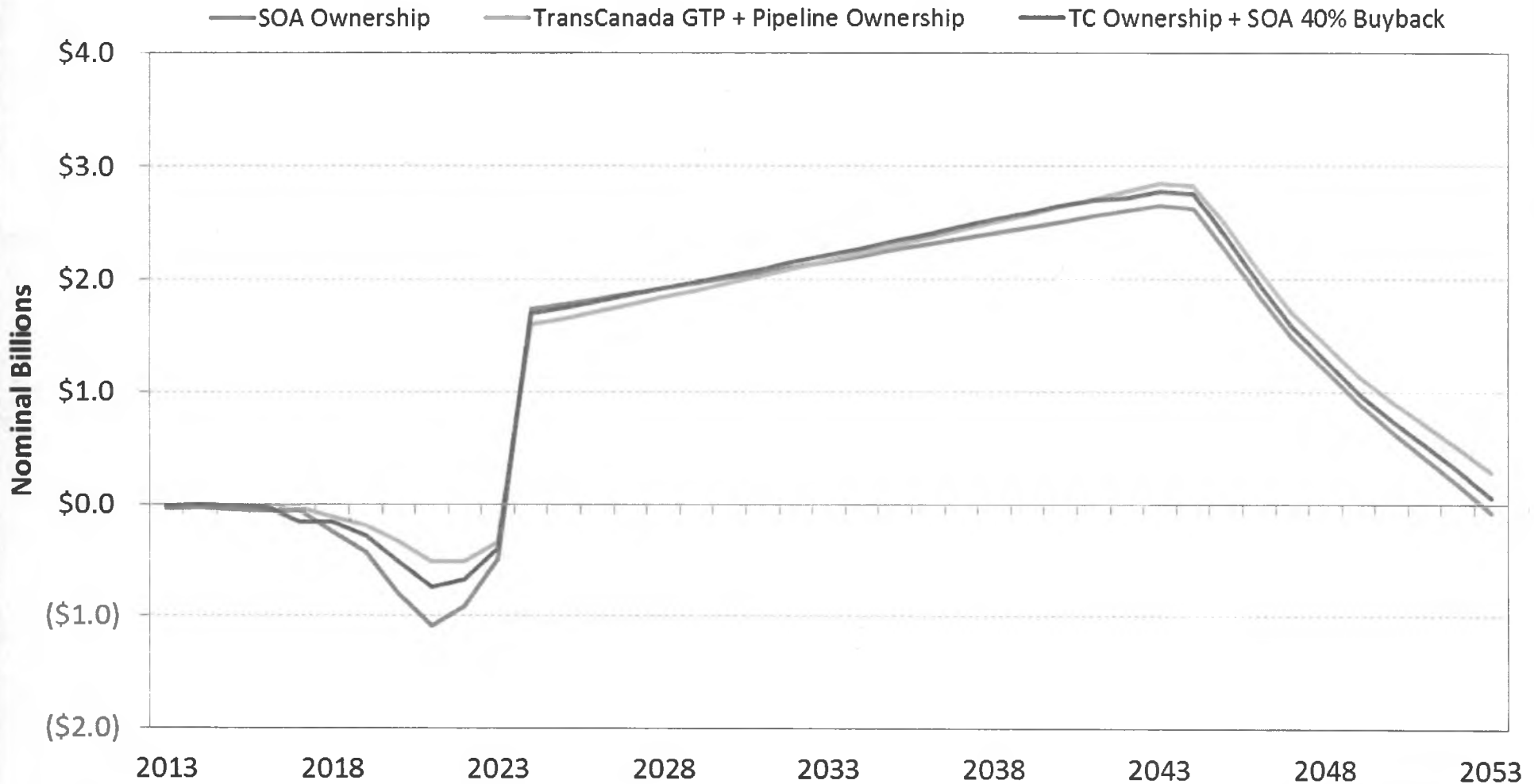
NPV to State of Alaska Associated with Equity Alternative



* NPV of cash flows over initial 30 years discounted at 10%; Cash flows exclude additional revenues to the State from the AKLNG Project such as upstream property and income taxes that are not impacted by TC participation. Values include the estimated impact of opportunity cost to the State which may not be a cash flow element.

STATE OF ALASKA ANNUAL CASH FLOWS ASSOCIATED WITH THE 20% EQUITY ALTERNATIVE*

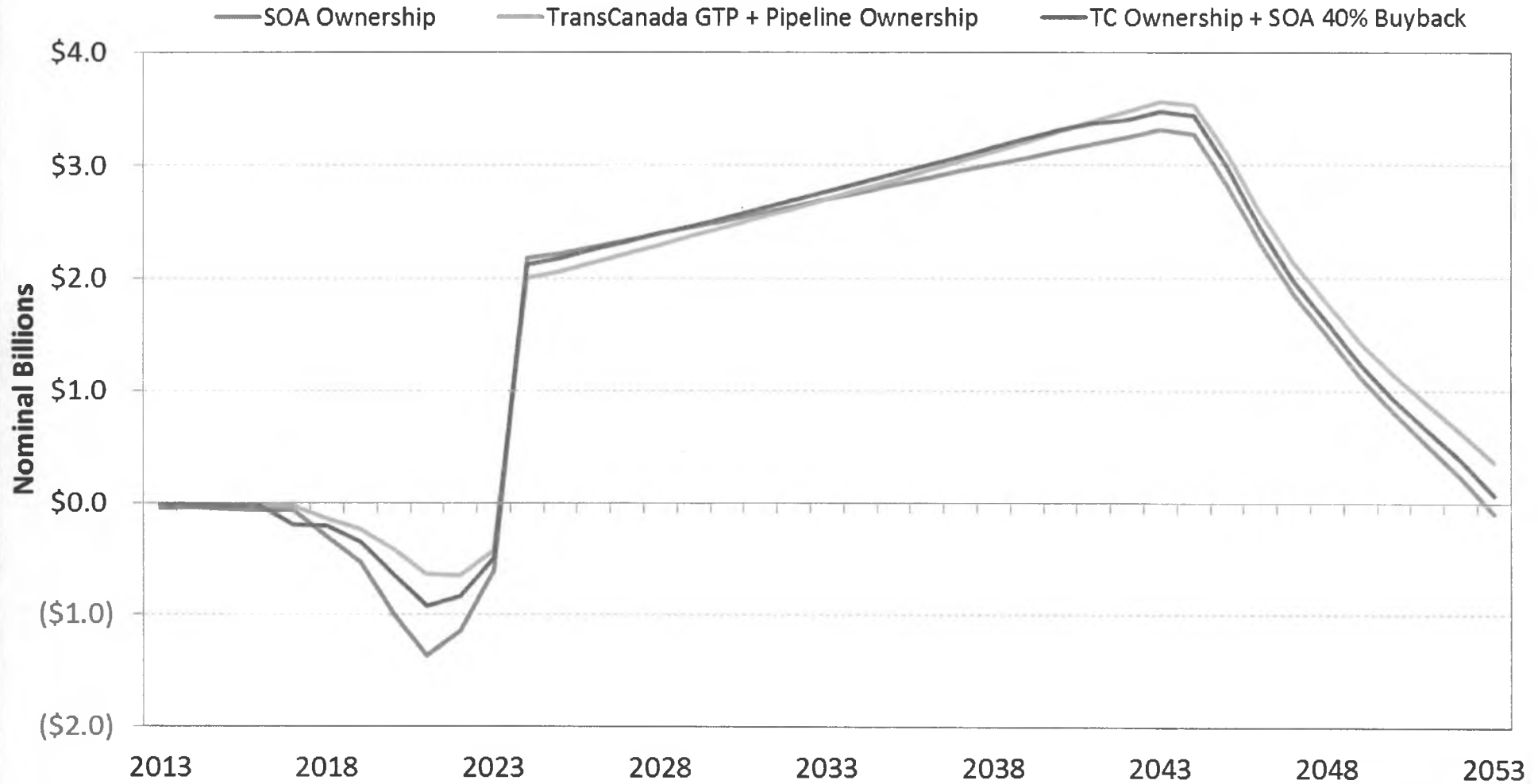
State of Alaska Annual Cash Flows Associated with 20% Equity Alternative



* Annual cash flows over initial 30 years. Cash flows exclude additional revenues to the State from the AK LNG Project such as upstream property and income taxes that are not impacted by TC participation. Values include the estimated impact of opportunity cost to the State which may not be a cash flow element.

STATE OF ALASKA ANNUAL CASH FLOWS ASSOCIATED WITH THE 25% EQUITY ALTERNATIVE*

State of Alaska Annual Cash Flows Associated with 25% Equity Alternative



* Annual cash flows over initial 30 years. Cash flows exclude additional revenues to the State from the AKLNG Project such as upstream property and income taxes that are not impacted by TC participation. Values include the estimated impact of opportunity cost to the State which may not be a cash flow element.

IMPACT OF CAPITAL STRUCTURE & RETURN ON EQUITY

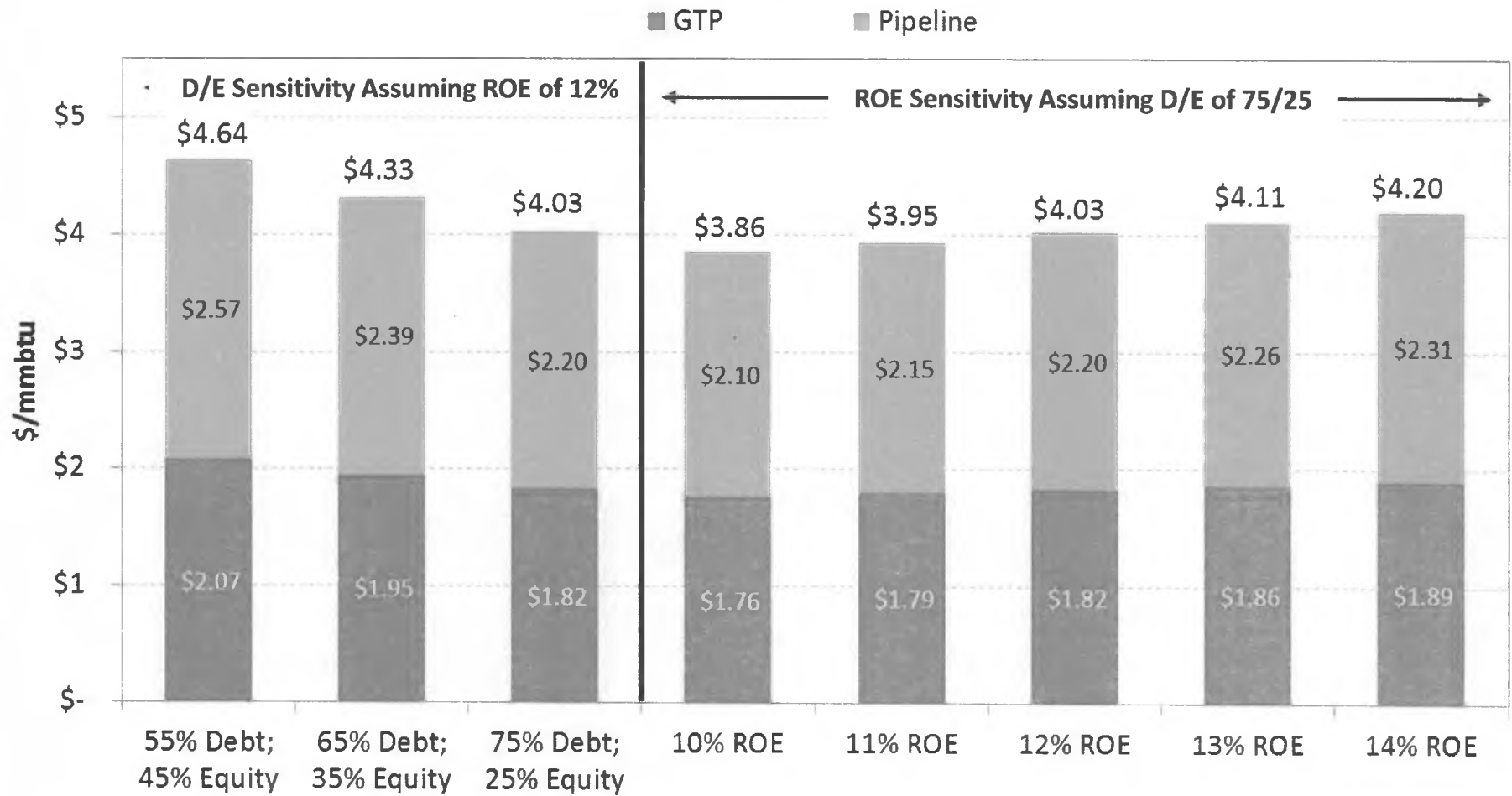
- **The purpose of this analysis is to examine the relative impact of the capital structure and the return on equity terms on the tariff for the GTP and pipeline and on the net present value to the State of Alaska**
- **This assessment examined the 25% Equity Alternative case, where TransCanada assumes the State's share of the GTP and Pipeline**
- **Sensitivity assumptions**
 - Base case assumptions reflect the proposed terms of 75% Debt/25% Equity with 12% ROE
 - Capital structure sensitivities examine shifts between debt and equity percentages in 10% increments from the base case
 - ROE sensitivities examine changes in ROE in increments of 1% from the base case

CAPITAL STRUCTURE & ROE – FINDINGS

- **Changes in the capital structure assumed to finance the AKLNG Project GTP and pipeline components could have a larger potential impact on the tariffs as well as net present value to the State than changes to the return on equity given to TransCanada**
- **Each 10% shift in the capital structure from debt to equity could increase the tariff on the GTP and pipeline by ~\$0.30/MMBtu and cause a loss of \$300 million in NPV₁₀ to the State**
- **In comparison, each 1% increase in the return on equity could increase the tariff on the GTP and pipeline by ~\$0.08/MMBtu and cause a loss of \$100 million in NPV₁₀ to the State**

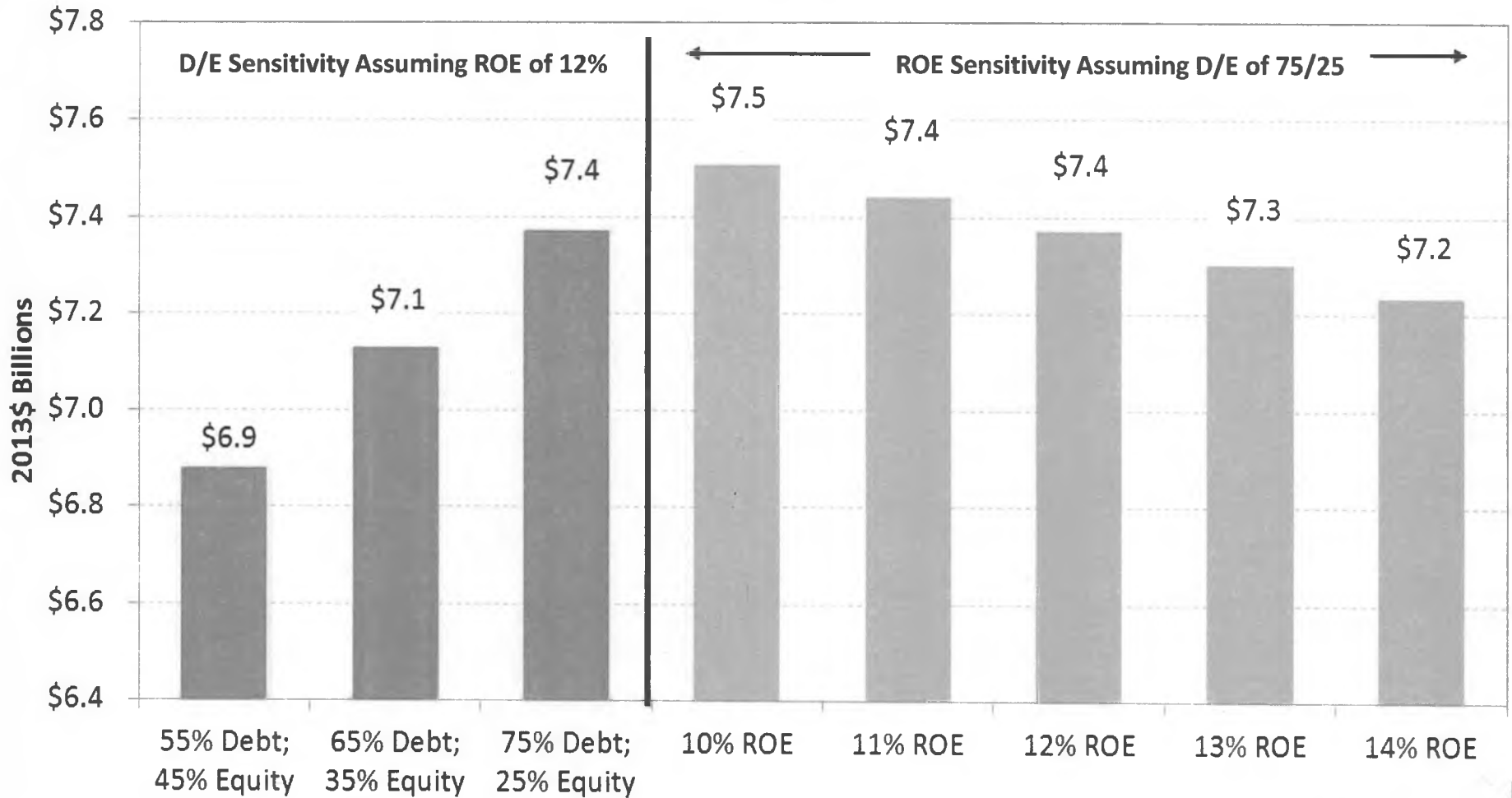
TARIFF ON GTP AND PIPELINE INCREASES BY ~\$0.30/MMBTU FOR EACH 10% INCREASE IN EQUITY WHILE INCREASING BY ~\$0.08/MMBTU FOR EACH 1% INCREASE IN ROE

TransCanada GTP + Pipeline Tariff



NPV TO THE STATE DECREASES BY ~\$300MM FOR EACH 10% INCREASE IN EQUITY WHILE DECREASING BY ~\$100MM FOR EACH 1% INCREASE IN ROE

State of Alaska NPV₁₀



EXPANSION ANALYSIS

- **As part of exploring an equity position in the Alaska LNG (“AKLNG”) Project, the State of Alaska (“the State” or “SOA”) has entered into a Heads of Agreement with parties that include the three major producers on the North Slope describing terms facilitating the development of the AKLNG Project.**
- **Pro-expansion principles have been considered within Appendix A of the HOA that allow any Alaska LNG Party to initiate expansion of the project within the construct of the principles agreed upon.**
- **Expansion of the AKLNG Project could provide key benefits to the State by facilitating further exploration and production activity on the North Slope by potentially providing an outlet to market for the natural gas produced.**

EXPANSION ANALYSIS – KEY ASSUMPTIONS

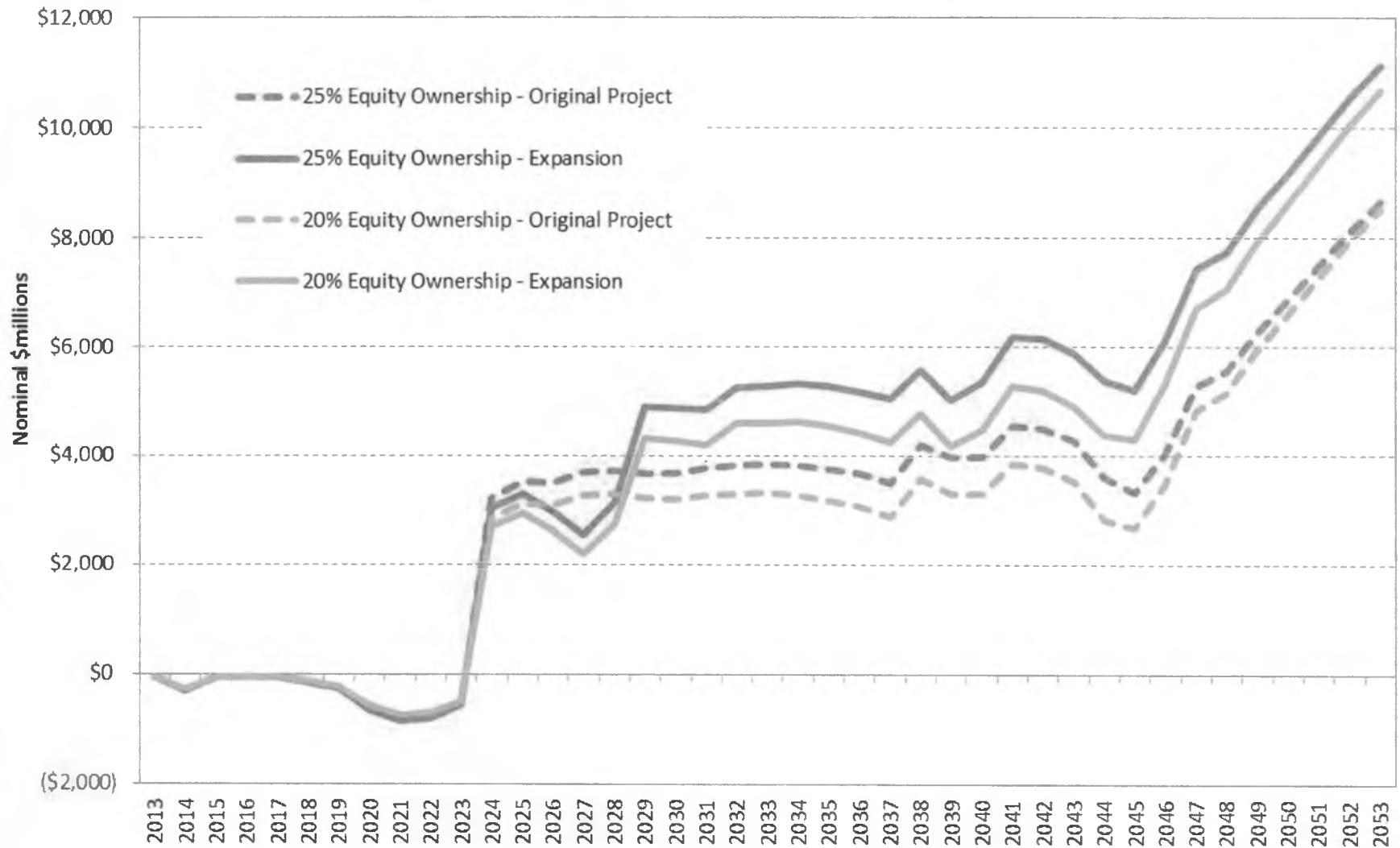
- **The purpose of this analysis is to evaluate the economic impact of an expansion of the AKLNG Project on the State of Alaska**
- **Two different alternate levels of State equity participation and State Gas Share – 20% and 25% – were analyzed**
- **Key terms proposed for TC’s services provided to the State include:**
 - Debt/Equity: 70/30 through first year of operation; 75/25 thereafter; 70/30 for expansions
 - Return on Equity: 12% plus rate tracker
 - Cost of Debt: 5% plus rate tracker
- **The capital structure and terms associated with the Producers’ portion of the original project include:**
 - Debt/Equity: 70/30; Return on Equity: 12%; Cost of Debt: 7%
- **Expansion analysis assumes one additional LNG train and equivalent capacity at the GTP Plant and pipeline are added to the project five years into its operation. The analysis examines a 30 year period from the in-service date of the project.**
- **Cost of expansion assumes a 20% reduction in GTP and LNG train costs relative to the original project due to economies. Additional compression costs for the pipeline are assumed to support the expansion volumes. Total expansion cost is ~\$10 billion compared to the original project of \$45 billion.**
- **This analysis assumes that gas for expansion comes from State lands. Benefit to the State shown here could be lower if part or all of the expansion gas comes from lands where the State has lower or no royalty/tax stake**

EXPANSION BENEFITS – FINDINGS

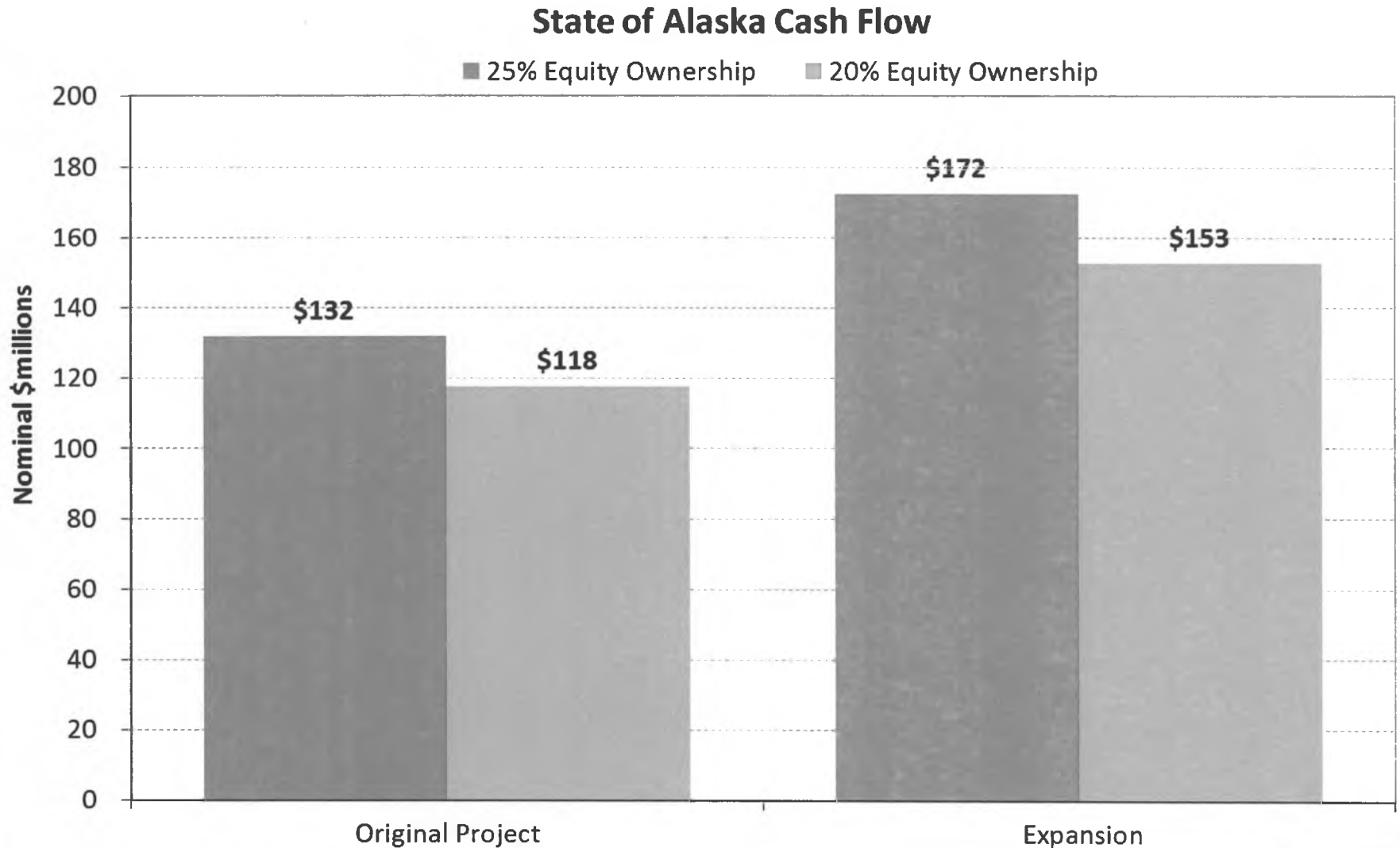
- **Expansion of the AKLNG Project can reduce the tariffs on the project for the original shippers due to economies of scale associated with an expansion**
 - The tariff advantages associated with expansion are impacted significantly by the capital structure of the original project for each of the AKLNG project owners as well as by that of the expansion
 - Tariffs for the original project could decrease by ~\$0.20/MMBtu assuming an expansion consistent with the 70/30 Debt/Equity structure proposed by TransCanada
- **Expansion of the project also results in higher revenues to the State driven by development of new gas resources and associated royalty and tax cash streams**
 - Potential increase in State revenues of ~\$40 billion in cash flows and of NPV10 of \$2 billion over the initial 30 years
 - The potential increase in State revenues from expansions are driven by the source of the yet-to-find gas resources

ANNUAL CASH FLOWS TO STATE OF ALASKA INCREASE WITH AN EXPANSION OF THE AKLNG PROJECT

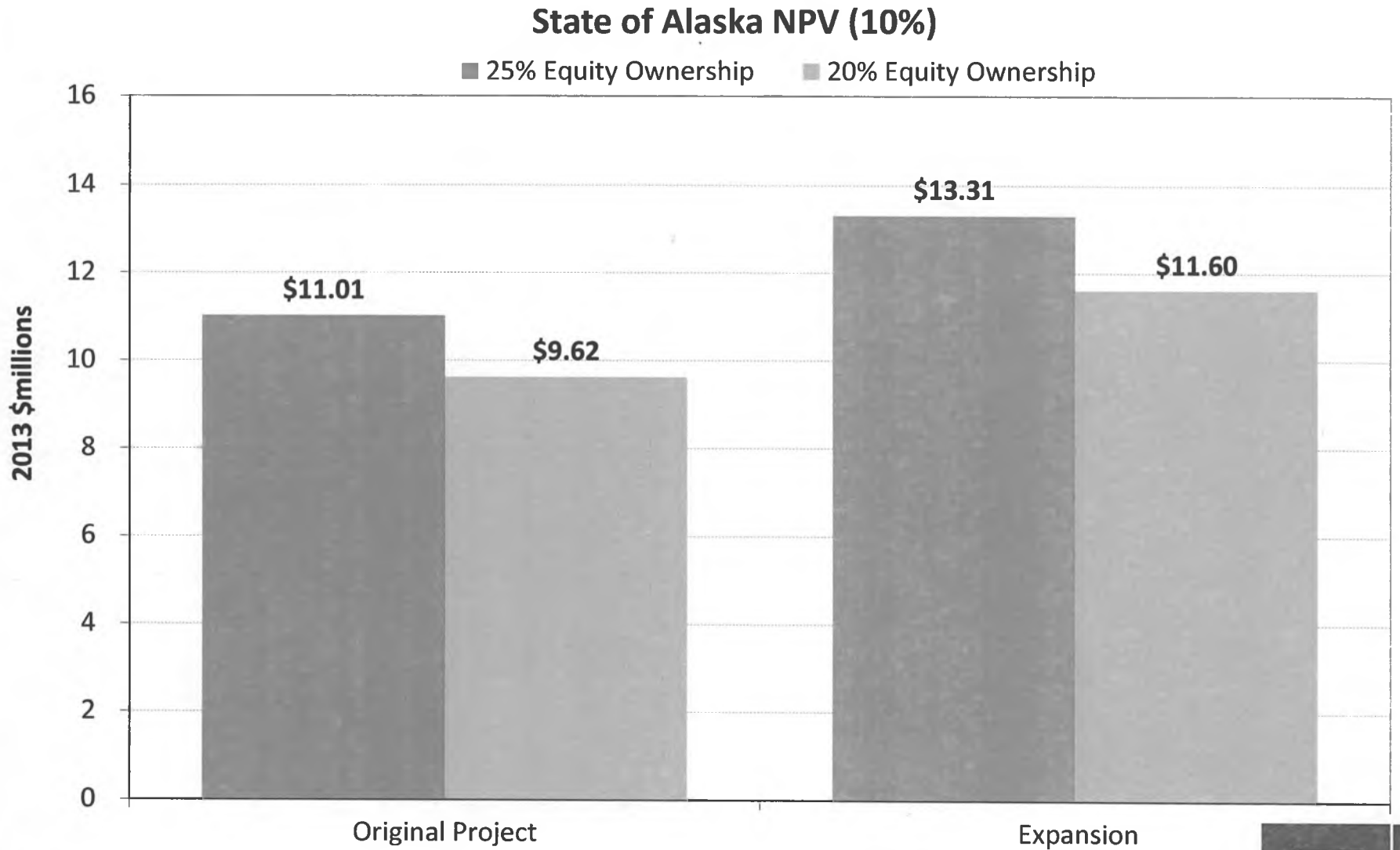
State of Alaska Cash Flow Forecast



STATE OF ALASKA TOTAL CASH FLOWS CAN INCREASE BY 30% WITH AN EXPANSION OF ONE LNG TRAIN



STATE OF ALASKA NPV₁₀ CAN POTENTIALLY INCREASE BY \$2 BILLION WITH AN EXPANSION



ALIGNMENT, IN KIND VS. IN VALUE & PROJECT / COST RISKS

Prepared for Senate Resources Committee
Juneau, Alaska > February 14, 2014

Janak Mayer, Partner > janak.mayer@analytica.info
Nikos Tsafos, Partner > nikos.tsafos@analytica.info

<http://analytica.info>

PRESENTERS

Janak Mayer > Nikos Tsafos

2



JANAK MAYER
PARTNER

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Before co-founding *enalytica*, Janak led the Upstream Analytics team at PFC Energy, focusing on fiscal terms analysis and project economic and financial evaluation, data management and data visualization.

Janak has modeled upstream fiscal terms in all of the world's major hydrocarbon regions, and has built economic and financial models to value prospective acquisition targets and develop strategic portfolio options for a wide range of international and national oil company clients. He has advised Alaska State Legislature for multiple years on reform of oil and gas taxation, providing many hours of expert testimony to Alaska's Senate and House Finance and Resources Committees.

Prior to his work as an energy consultant, Janak advised major minerals industry clients on a range of controversial environmental and social risk issues, from uranium mining through to human rights and climate change. He has advised bankers at Citigroup and policy-makers at the US Treasury Department on the management and mitigation of environmental and social impacts in major projects around the world, and has undertaken macroeconomic research with senior development economists at the World Bank and the Peterson Institute for International Economics.

Janak holds an MA with distinction in international relations and economics from the Johns Hopkins School of Advanced International Studies (SAIS), and a BA with first-class honors from the University of Adelaide, Australia.

PRESENTERS

Janak Mayer > Nikos Tsafos

3



NIKOS TSAFOS
PARTNER

enalytica

NIKOS.TSAFOS@ENALYTICA.INFO

Nikos Tsafos has a diverse background in the private, public and non-profit sectors. He is currently a founding partner at *enalytica*. In his 7 ½ years with PFC Energy, Nikos advised the world's largest oil and gas companies on some of their most complex and challenging projects; he also played a pivotal role in turning the firm into one of the top natural gas consultancies in the world, with responsibilities that included product design, business development, consulting oversight and research direction.

Prior to PFC Energy, Nikos was at the Center for Strategic and International Studies (CSIS) in Washington, DC where he covered political, economic, and military issues in the Gulf, focused on oil wealth, regime stability and foreign affairs. Before CSIS, he was in the Greek Air Force, and prior to his military service, Nikos worked on channeling investment from Greek ship-owners to Chinese shipyards.

Nikos has also written extensively on the domestic and international dimensions of the Greek debt crisis. His blog (Greek Default Watch) was listed as one of "Europe's Top Economic Blogs" by the Social Europe Journal, and his book "Beyond Debt: The Greek Crisis in Context" was published in March 2013.

Nikos holds a BA with distinction in international relations and economics from Boston University and an MA with distinction in international relations from the Johns Hopkins School of Advanced International Studies (SAIS).

IF LNG WERE OIL › IN KIND VS. IN VALUE › PRICE & COST EXPOSURE

oil netback › oil vs. gas prices › oil vs. gas midstream › LNG netback › LNG with lower oil price › LNG with higher costs › conclusion

FY 2015 PRODUCTION TAX ESTIMATE USING INCOME STATEMENT FORMAT

	Price	Barrels (Thousands)	Value (\$ million)
Avg ANS Oil Price (\$/bbl) & Daily Production	\$105.06	498	\$52.4
Annual Production			
Total		181,912	\$19,111.7
Royalty, Federal & other barrels		(23,301)	(\$2,448.0)
Taxable bbls from companies w/ tax liability		158,611	\$16,663.7
Downstream (Transportation) Costs (\$/bbl)			
ANS Marine Transportation	(\$3.46)		
TAPS Tariff	(\$6.18)		
Other	(\$0.40)		
Total Transportation Costs	(\$10.03)	158,611	(\$1,591.0)
Deductible Lease Expenditures			
Deductible Operating Expenditures	(\$17.91)		(\$2,840.3)
Deductible Capital Expenditures	(\$28.08)		(\$4,453.4)
Total Lease Expenditures	(\$45.99)	158,611	(\$7,293.7)
Production Tax			
Gross Value Reduction			(\$63.8)
Production Tax Value (PTV)	\$48.64		\$7,715.2
Base Tax (35%*PTV)			\$2,700.3
Total Tax before credits			\$2,700.3

OIL VALUE CHAIN

Oil ~\$105/bbl

Midstream costs ~\$10/bbl

Lease expenditures \$46/bbl

Production tax on ~\$49/bbl netback

SOURCE: DEPARTMENT OF REVENUE, REVENUE SOURCES BOOK, FALL 2013, P. 106

IF LNG WERE OIL › IN KIND VS. IN VALUE › PRICE & COST EXPOSURE

oil netback › oil vs. gas prices › oil vs. gas midstream › LNG netback › LNG with lower oil price › LNG with higher costs › conclusion

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Production Tax Value (PTV)	\$48.64		\$7,715.2
Base Tax (35%*PTV)			\$2,700.3
Total Tax before credits			\$2,700.3

PRICE FOR ALASKAN GAS WILL BE:



Less transparent

no readily available published price like ANS WC

Less consistent by destination

contract-by-contract differences can be large

Likely link to Japan Crude Oil Cocktail, JCC

in 2004-2013, JCC traded at \$0.22/bbl discount to ANS

Lower value vs. oil (thermal equivalency)

e.g. \$100/bbl ≠ \$100/boe of LNG

\$100/bbl = \$78-\$90/boe (13%-15% "slope")

SOURCE: DEPARTMENT OF REVENUE, REVENUE SOURCES BOOK, FALL 2013, P. 106

IF LNG WERE OIL › IN KIND VS. IN VALUE › PRICE & COST EXPOSURE

oil netback › oil vs. gas prices › oil vs. gas midstream › LNG netback › LNG with lower oil price › LNG with higher costs › conclusion

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Production Tax Value (PTV)	\$48.64		\$7,715.2
Base Tax (35%*PTV)			\$2,700.3
Total Tax before credits			\$2,700.3

MIDSTREAM COSTS WILL BE:



Order of magnitude higher

Gas is significantly more expensive to transport

Tariff not regulated by FERC

FERC will regulate permitting, not rate-setting

Tariff highly sensitive to capital structure

return on equity and /or assumed debt/equity ratio

SOURCE: DEPARTMENT OF REVENUE, REVENUE SOURCES BOOK, FALL 2013, P. 106

IF LNG WERE OIL › IN KIND VS. IN VALUE › PRICE & COST EXPOSURE

oil netback › oil vs. gas prices › oil vs. gas midstream › LNG netback › LNG with lower oil price › LNG with higher costs › conclusion

INDICATIVE TAX BEFORE CREDITS FOR ALASKA LNG PROJECT @ ANS

	Price	Barrels (Thousands)	Value (\$ million)
Avg LNG Price (\$/boe) & Daily Production	\$81.00	384	\$31.1
Annual Production			
Total		140,306	\$11,364.8
Royalty, Federal & other barrels		(19,643)	(\$1,591.1)
Taxable bbls from companies w/ tax liability		120,664	\$9,773.8
Downstream (Transportation) Costs (\$/boe)			
Marine Transportation	(\$6.00)		(\$724.0)
Pipeline & GTP Tariff	(\$24.18)		(\$2,917.6)
Liquefaction Tariff	(\$36.00)		(\$4,343.9)
Total Transportation Costs	(\$66.18)	120,664	(\$7,985.5)
Deductible Lease Expenditures			
Deductible Operating Expenditures	(\$3.00)		(\$362.0)
Deductible Capital Expenditures	(\$3.00)		(\$362.0)
Total Lease Expenditures	(\$6.00)	120,664	(\$724.0)
Production Tax			
Gross Value Reduction			\$0.0
Production Tax Value (PTV)	\$8.82		\$1,064.3
Base Tax (35%*PTV)			\$372.5
Total Tax before credits			\$372.5

INDICATIVE LNG CHAIN: \$100/BBL

At \$100/bbl, LNG price ~\$81/boe (13.5%)

Midstream ~\$66/boe

Upstream ~\$6/boe

Limited netback to tax (less than \$9/boe)

SOURCE: ANALYTICA ANAL OF REVENUE, REVENUE SOURCES BOOK, FALL 2013, P. 106

IF LNG WERE OIL › IN KIND VS. IN VALUE › PRICE & COST EXPOSURE

oil netback › oil vs. gas prices › oil vs. gas midstream › LNG netback › LNG with lower oil price › LNG with higher costs › conclusion

INDICATIVE TAX BEFORE CREDITS FOR ALASKA LNG PROJECT @ ANS

	Price	Barrels (Thousands)	Value (\$ million)
Avg LNG Price (\$/boe) & Daily Production	\$72.18	384	\$27.7
Annual Production			
Total		140,306	\$10,127.3
Royalty, Federal & other barrels		(19,643)	(\$1,417.8)
Taxable bbls from companies w/ tax liability		120,664	\$8,709.5
Downstream (Transportation) Costs (\$/boe)			
Marine Transportation	(\$6.00)		(\$724.0)
Pipeline & GTP Tariff	(\$24.18)		(\$2,917.6)
Liquefaction Tariff	(\$36.00)		(\$4,343.9)
Total Transportation Costs	(\$66.18)	120,664	(\$7,985.5)
Deductible Lease Expenditures			
Deductible Operating Expenditures	(\$3.00)		(\$362.0)
Deductible Capital Expenditures	(\$3.00)		(\$362.0)
Total Lease Expenditures	(\$6.00)	120,664	(\$724.0)
Production Tax			
Gross Value Reduction			\$0.0
Production Tax Value (PTV)	\$0.00		\$0.0
Base Tax (35%*PTV)			\$0.0
Total Tax before credits			\$0.0

INDICATIVE LNG CHAIN: \$89/BBL ANS



A drop to \$89/bbl ANS ...

... wipes out any production tax value



IF LNG WERE OIL › IN KIND VS. IN VALUE › PRICE & COST EXPOSURE

oil netback › oil vs. gas prices › oil vs. gas midstream › LNG netback › LNG with lower oil price › LNG with higher costs › conclusion

INDICATIVE TAX BEFORE CREDITS FOR ALASKA LNG PROJECT @ ANS

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Annual Production			
Total		140,306	\$11,364.8
Royalty, Federal & other barrels		(19,643)	(\$1,591.1)
Taxable bbls from companies w/ tax liability		120,664	\$9,773.8
Downstream (Transportation) Costs (\$/boe)			
Marine Transportation	(\$6.73)		(\$812.4)
Pipeline & GTP Tariff	(\$27.13)		(\$3,274.2)
Liquefaction Tariff	(\$40.40)		(\$4,874.7)
Total Transportation Costs	(\$74.27)	120,664	(\$8,961.3)
Deductible Lease Expenditures			
Deductible Operating Expenditures	(\$3.37)		(\$406.2)
Deductible Capital Expenditures	(\$3.37)		(\$406.2)
Total Lease Expenditures	(\$6.73)	120,664	(\$812.4)
Production Tax			
Gross Value Reduction			\$0.0
Production Tax Value (PTV)	\$0.00		\$0.0
Base Tax (35%*PTV)			\$0.0
Total Tax before credits			\$0.0

INDICATIVE LNG CHAIN: HIGHER COSTS



A 12.2% hike in costs / tariffs



... wipes out any production tax value



IF LNG WERE OIL › IN KIND VS. IN VALUE › PRICE & COST EXPOSURE

oil netback › oil vs. gas prices › oil vs. gas midstream › LNG netback › LNG with lower oil price › LNG with higher costs › conclusion

INDICATIVE TAX BEFORE CREDITS FOR ALASKA LNG PROJECT @ ANS

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Deductible Capital Expenditures	(\$3.00)		(\$362.0)
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Production Tax			
Gross Value Reduction			\$0.0
Production Tax Value (PTV)	\$8.82		\$1,064.3
Base Tax (35%*PTV)			\$372.5
Total Tax before credits			\$372.5

IMPLICATIONS FOR STATE OF ALASKA



Fair market price critical for top line

Midstream, midstream, midstream



Upstream secondary to midstream

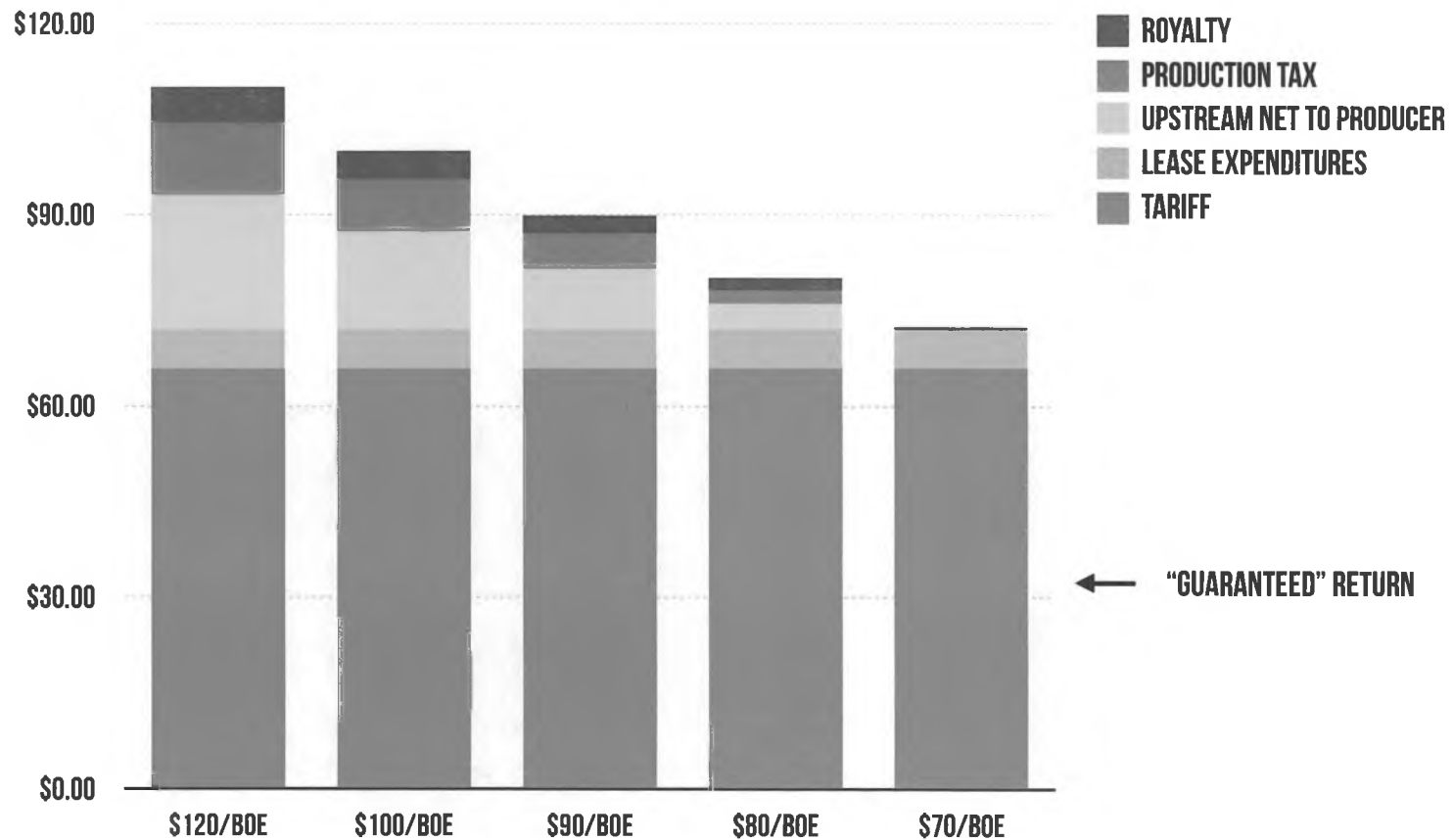


Wellhead insufficient to drive state take



RIV MAKES UPSTREAM THE SOLE PRICE ABSORBER

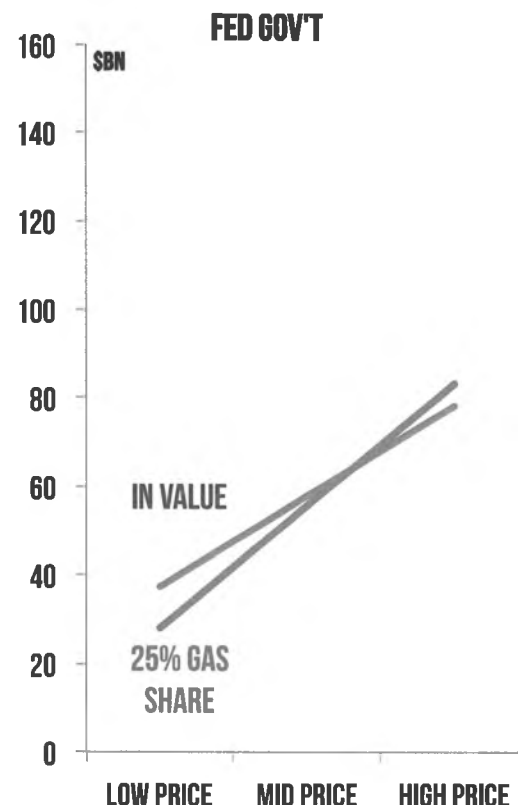
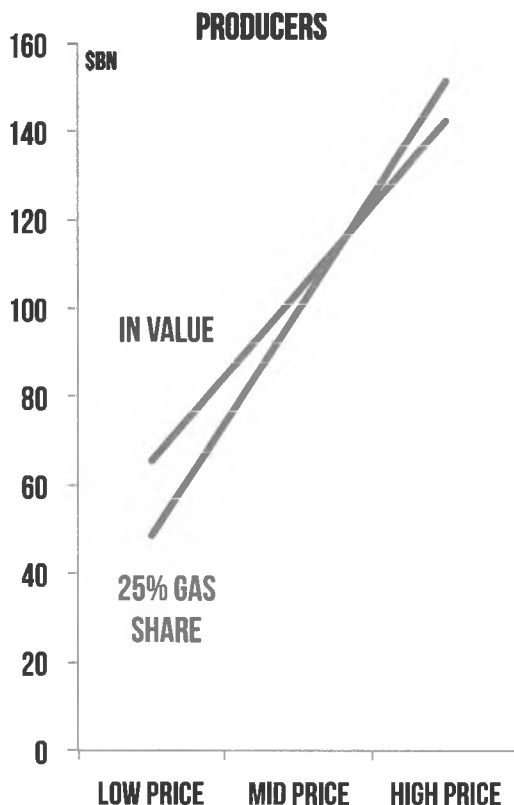
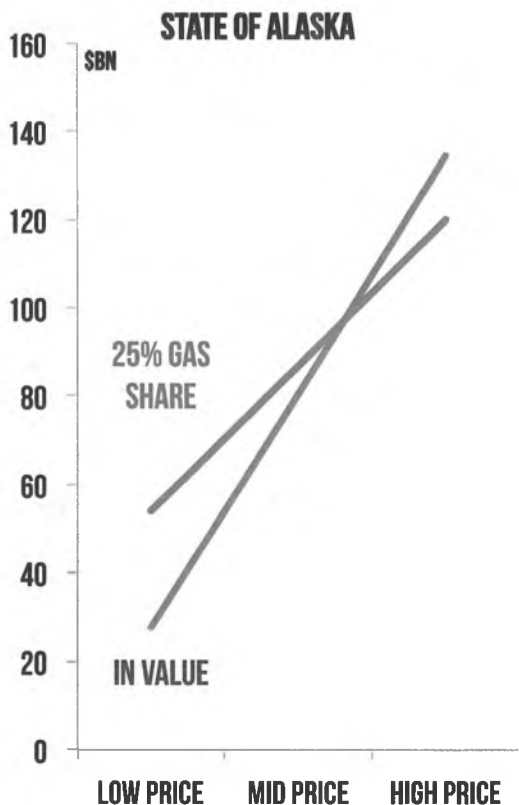
Fixed nature of tariff in 'in Value' alternative amplifies impact of price movement on state returns



IN KIND W/ EQUITY OFFERS MORE DOWNSIDE PROTECTION

Price-absorbing in-value structure protects producers, not state, in low price environment

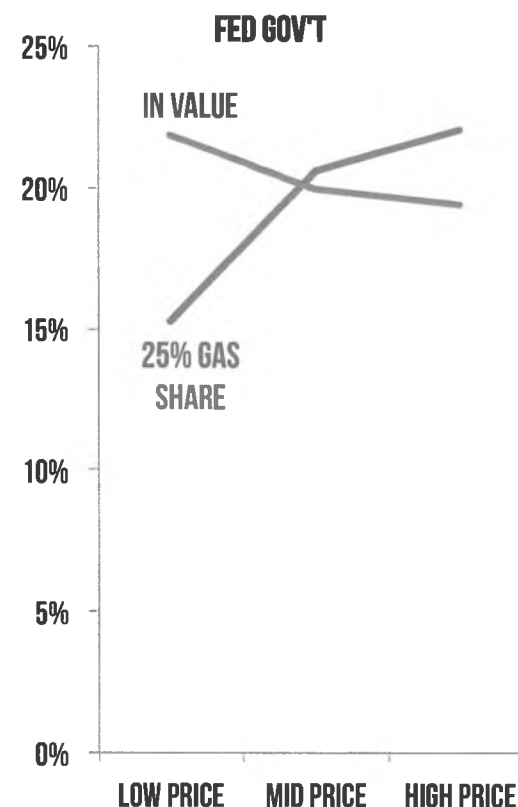
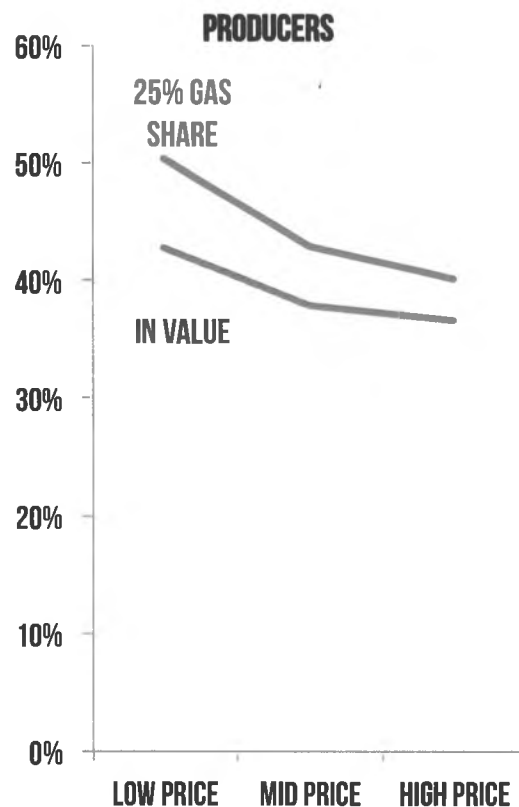
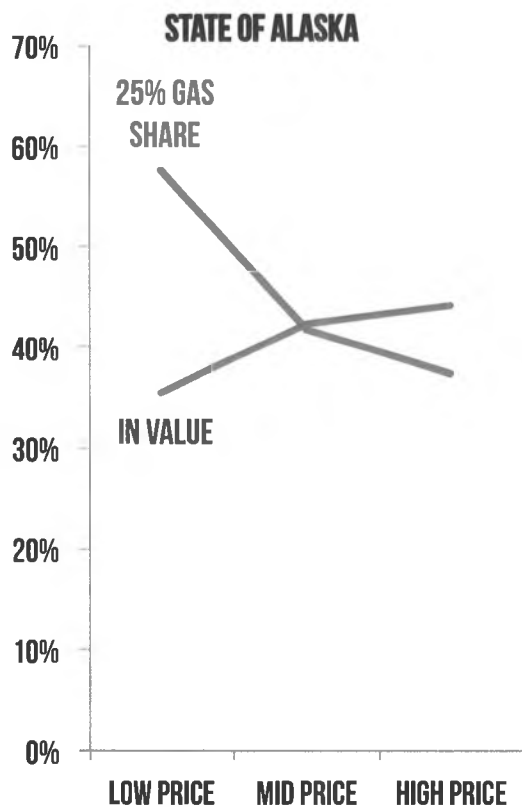
CUMULATIVE CASH FLOWS OVER PROJECT LIFE



SOA TAX STATUS TRANSFERS VALUE FROM FED TO SOA

Price-absorbing in-value structure protects producers, not state, in low price environment

CUMULATIVE CASH FLOWS OVER PROJECT LIFE



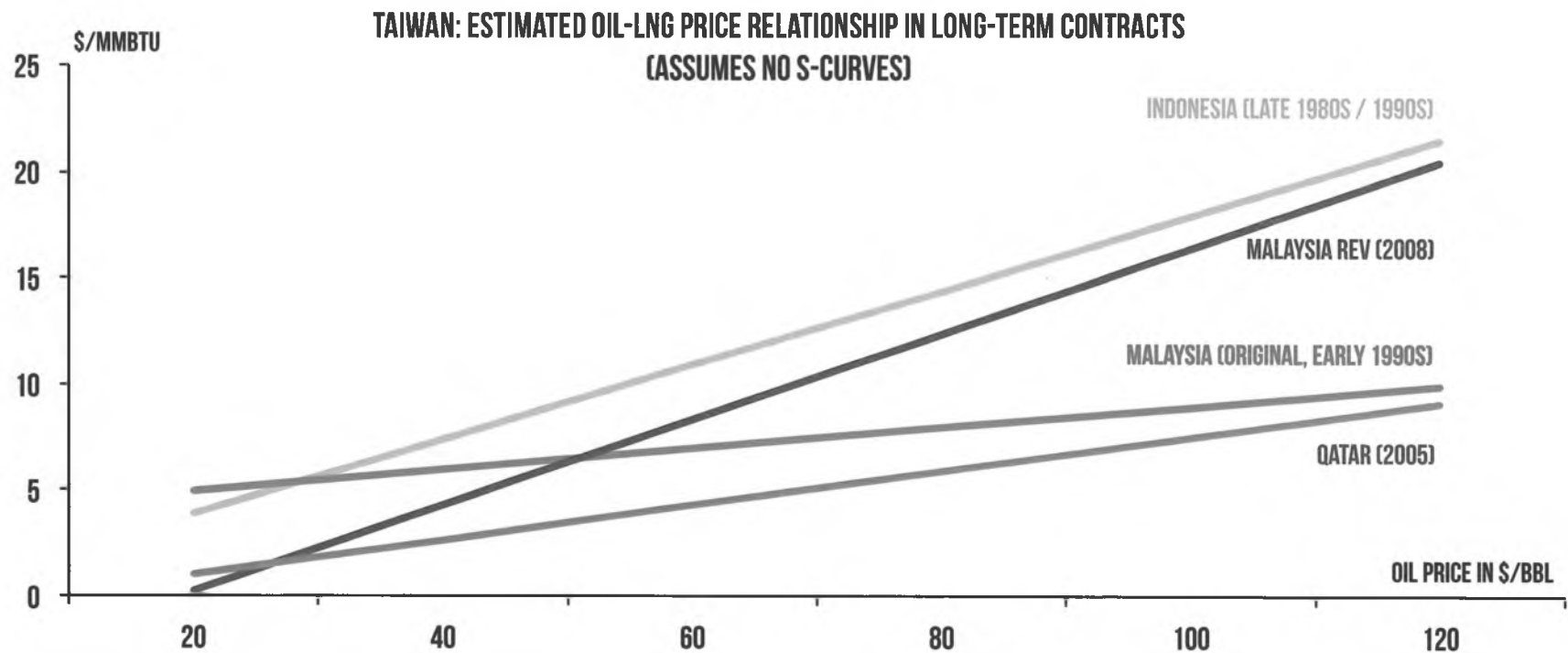
price exposure › volatility protection › cost escalation and delay risks

PRICE EXPOSURE DEFINED AT CONTRACT SIGNING

Oil linkage does not mean identical linkage to oil (e.g. Taiwan, below); bargaining power defines linkage

New contracts do not impact existing deals (e.g. new Henry Hub-based LNG vs. existing oil-linked SPAs)

But if price is seriously out of sync with fundamentals, parties can trigger a review clause



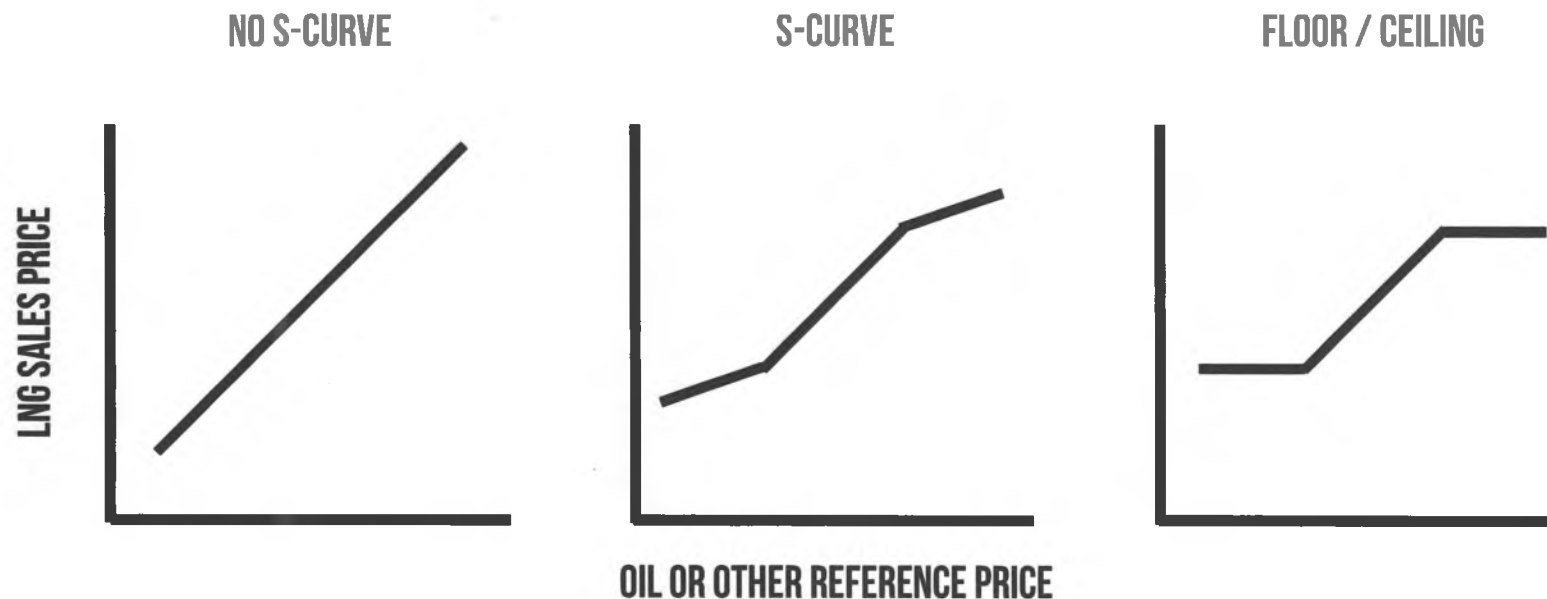
SOURCE: ENALYTICA BASED ON DATA FROM TAIWAN'S CUSTOMS ADMINISTRATION, MINISTRY OF FINANCE ([HTTP://WWW.CUSTOMS.GOV.TW/STATISTICSWEBEN/IESEARCH.ASPX](http://www.customs.gov.tw/statisticsweb/en/iesearch.aspx))

EXPENSIVE PROJECTS CAN HEDGE AGAINST VOLATILITY

“S-curves” are clauses that change the relationship between oil and gas above or below thresholds

Instead of a linear link, gas prices do not rise/fall as much if oil prices rise/fall above certain thresholds

They reduce downside risk by forgoing some upside—they can even provide a floor/ceiling on prices



IF LNG WERE OIL › IN KIND VS. IN VALUE › PRICE & COST EXPOSURE

price exposure › volatility protection › cost escalation and delay risks

PROJECT	SANCTIONED	TARGET DATE	ACTUAL DATE	DELAY	BUDGET BN	COST BN	% OVERRUN
Snøhvit (Norway)	Mar-02	2006	Sep-07	1.5 years	NOK39.50	NOK48.00	21.5%
Egyptian LNG T1	Sep-02	Aug-05	May-05	3 months early	\$1.1	on budget	0%
Sakhalin-2 (Russia)	May-03	2007	Mar-09	2 years	\$10.0	\$22.0	120.0%
Atlantic LNG T4 (Trinidad)	Jun-03	2005	Dec-05	on time	\$1.2	on budget	0%
Egyptian LNG T2	Jul-03	Jun-06	Sep-05	9 months early	\$0.6	on budget	0%
Equatorial Guinea	Jun-04	Late 2007	May-07	6 months early	\$1.5	on budget	0%
North West Shelf (Australia)	Jun-05	2008	Sep-08	on time	AUS\$2	AUS\$2.6	30.0%
Yemen	Aug-05	Dec-08	Nov-09	1 year	\$3.7	\$4.5	21.6%
Peru	Jan-07	mid 2010	Jun-10	on time	\$3.8	\$3.9	2.6%
Pluto	Jun-07	Early 2011	May-12	1.5 years	AUS\$11.2	AUS\$14.9	33.0%
Skikda LNG (Algeria)	Jun-07	2011	Mar-13	2 years	\$2.8	?	?
Angola	Dec-07	Early 2012	Jun-13	1.5-2 years	?	\$10.0	?
Gorgon (Australia)	Sep-09	2014	n/a	n/a	\$37.0	\$54.0	45.9%
Papua New Guinea	Dec-09	2014	n/a	n/a	\$15.0	\$19.0	26.7%
Queensland Curtis (Australia)	Nov-10	2014	n/a	n/a	\$15.0	\$20.5	36.7%
Gladstone LNG (Australia)	Jan-12	2015	n/a	n/a	\$16.0	\$18.5	15.6%

SOURCE: ENALYTICA BASED ON COMPANY PRESS RELEASES AND INDUSTRY PRESS

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COMPETITIVENESS, PROJECT STRUCTURE & CASH EXPOSURE

Prepared for Senate Resources Committee
Juneau, Alaska > February 20, 2014

Janak Mayer, Partner > janak.mayer@enalytica.info
Nikos Tsafos, Partner > nikos.tsafos@enalytica.info

<http://enalytica.info>

PRESENTERS

Janak Mayer > Nikos Tsafos

2



JANAK MAYER
PARTNER

enalytica

JANAK.MAYER@ENALYTICA.INFO

Before co-founding *enalytica*, Janak led the Upstream Analytics team at PFC Energy, focusing on fiscal terms analysis and project economic and financial evaluation, data management and data visualization.

Janak has modeled upstream fiscal terms in all of the world's major hydrocarbon regions, and has built economic and financial models to value prospective acquisition targets and develop strategic portfolio options for a wide range of international and national oil company clients. He has advised Alaska State Legislature for multiple years on reform of oil and gas taxation, providing many hours of expert testimony to Alaska's Senate and House Finance and Resources Committees.

Prior to his work as an energy consultant, Janak advised major minerals industry clients on a range of controversial environmental and social risk issues, from uranium mining through to human rights and climate change. He has advised bankers at Citigroup and policy-makers at the US Treasury Department on the management and mitigation of environmental and social impacts in major projects around the world, and has undertaken macroeconomic research with senior development economists at the World Bank and the Peterson Institute for International Economics.

Janak holds an MA with distinction in international relations and economics from the Johns Hopkins School of Advanced International Studies (SAIS), and a BA with first-class honors from the University of Adelaide, Australia.

PRESENTERS

Janak Mayer > Nikos Tsafos



NIKOS TSAFOS
PARTNER

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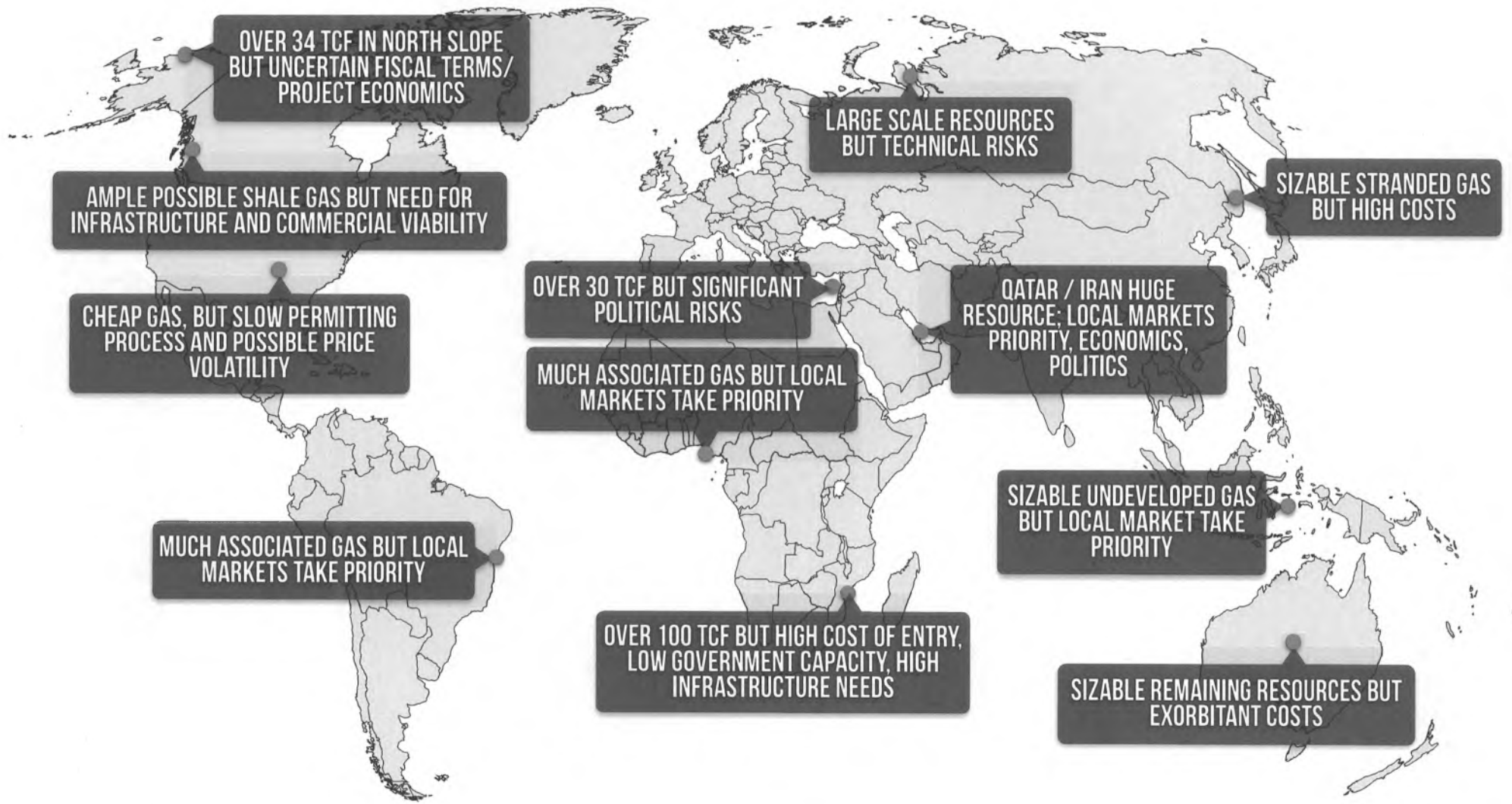
Nikos Tsafos has a diverse background in the private, public and non-profit sectors. He is currently a founding partner at *enalytica*. In his 7 ½ years with PFC Energy, Nikos advised the world's largest oil and gas companies on some of their most complex and challenging projects; he also played a pivotal role in turning the firm into one of the top natural gas consultancies in the world, with responsibilities that included product design, business development, consulting oversight and research direction.

Prior to PFC Energy, Nikos was at the Center for Strategic and International Studies (CSIS) in Washington, DC where he covered political, economic, and military issues in the Gulf, focused on oil wealth, regime stability and foreign affairs. Before CSIS, he was in the Greek Air Force, and prior to his military service, Nikos worked on channeling investment from Greek ship-owners to Chinese shipyards.

Nikos has also written extensively on the domestic and international dimensions of the Greek debt crisis. His blog (Greek Default Watch) was listed as one of "Europe's Top Economic Blogs" by the Social Europe Journal, and his book "Beyond Debt: The Greek Crisis in Context" was published in March 2013.

Nikos holds a BA with distinction in international relations and economics from Boston University and an MA with distinction in international relations from the Johns Hopkins School of Advanced International Studies (SAIS).

AK LNG IS COMPETING IN A WORLD WITH MANY CHOICES




BUT WE'VE BEEN HERE BEFORE IN THE MID/LATE 2000S



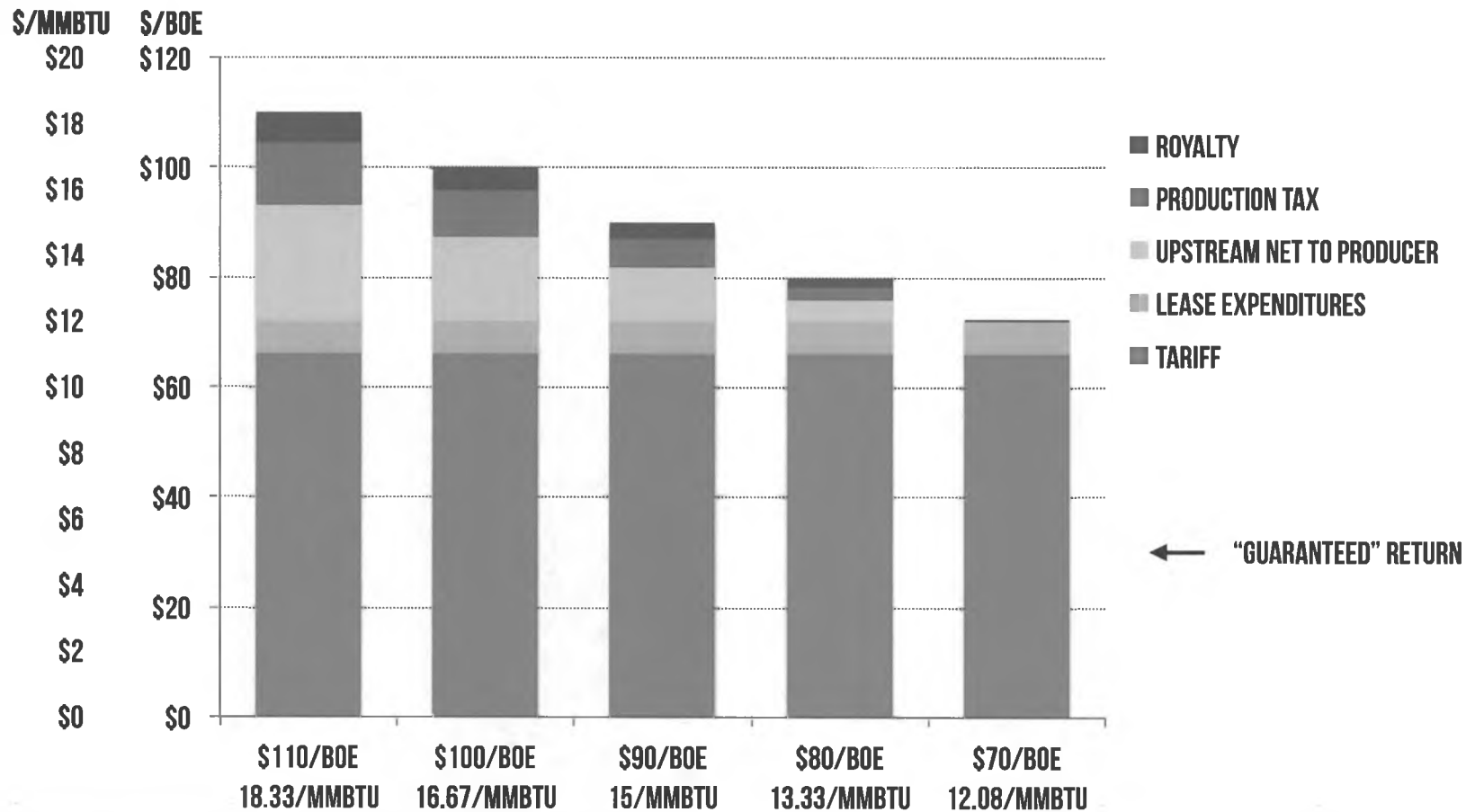
AK LNG OUT OF THE MONEY? › IN KIND VS. IN VALUE › MIDSTREAM OPTIONS › CASH EXPOSURE

project structure options › upstream is shock absorber › cash flow comparison › value split

<u>System</u>		<u>SOA ownership percent</u>			<u>SOA share of CAPEX & OPEX</u>			<u>SOA cash commitments</u>	
	<u>Value / Kind</u>	<u>Upstream</u>	<u>GTP & Pipe</u>	<u>LNG</u>	<u>Upstream</u>	<u>GTP & Pipe</u>	<u>LNG</u>	<u>Debt</u>	<u>Tariffs</u>
	Status Quo	in value	0%	0%	0%	Indirect (taxes)	0%	0%	No debt Tariff matters for valuation
	HOA	in kind	0%	25%	25%	Indirect (taxes)	25%	25%	Principal and interest Tariff only notional
MOU Option 1	in kind	0%	10% (40% x 25%)	25%	Indirect (taxes)	10% (40% x 25%)	25%	Principal and interest	Tariff payable to T/C
MOU Option 2	in kind	0%	0%	25%	Indirect (taxes)	0%	25%	Principal and interest	Tariff payable to T/C

RIV MAKES UPSTREAM THE SOLE PRICE ABSORBER

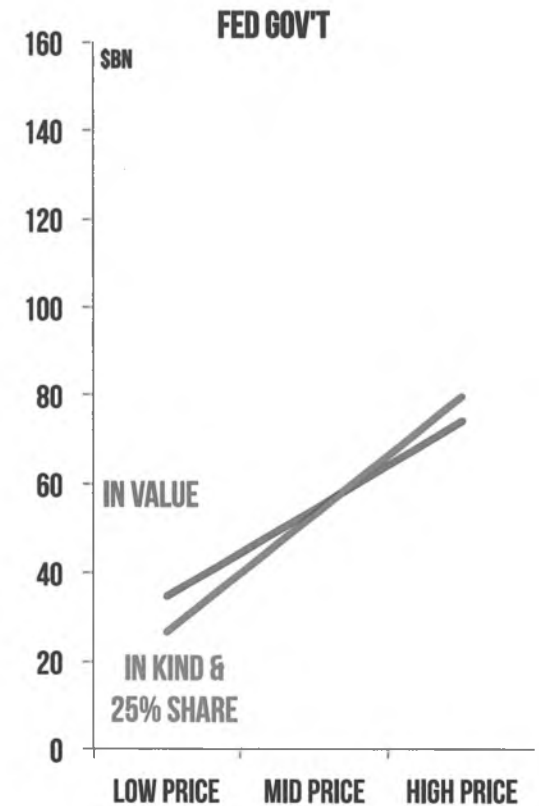
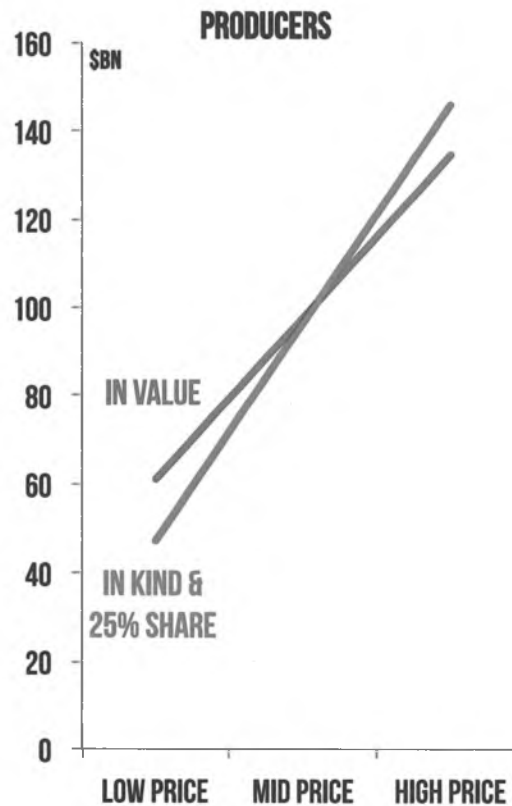
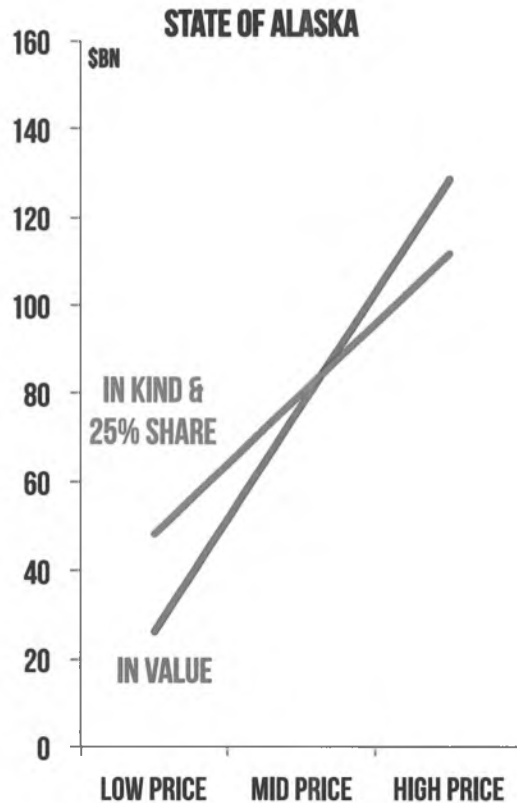
Fixed nature of tariff in 'in Value' alternative amplifies impact of price movement on state returns



IN KIND W/ EQUITY OFFERS MORE DOWNSIDE PROTECTION

In-value structure protects producers, not state, in low price environment because of tariff component

CUMULATIVE CASH FLOWS OVER PROJECT LIFE

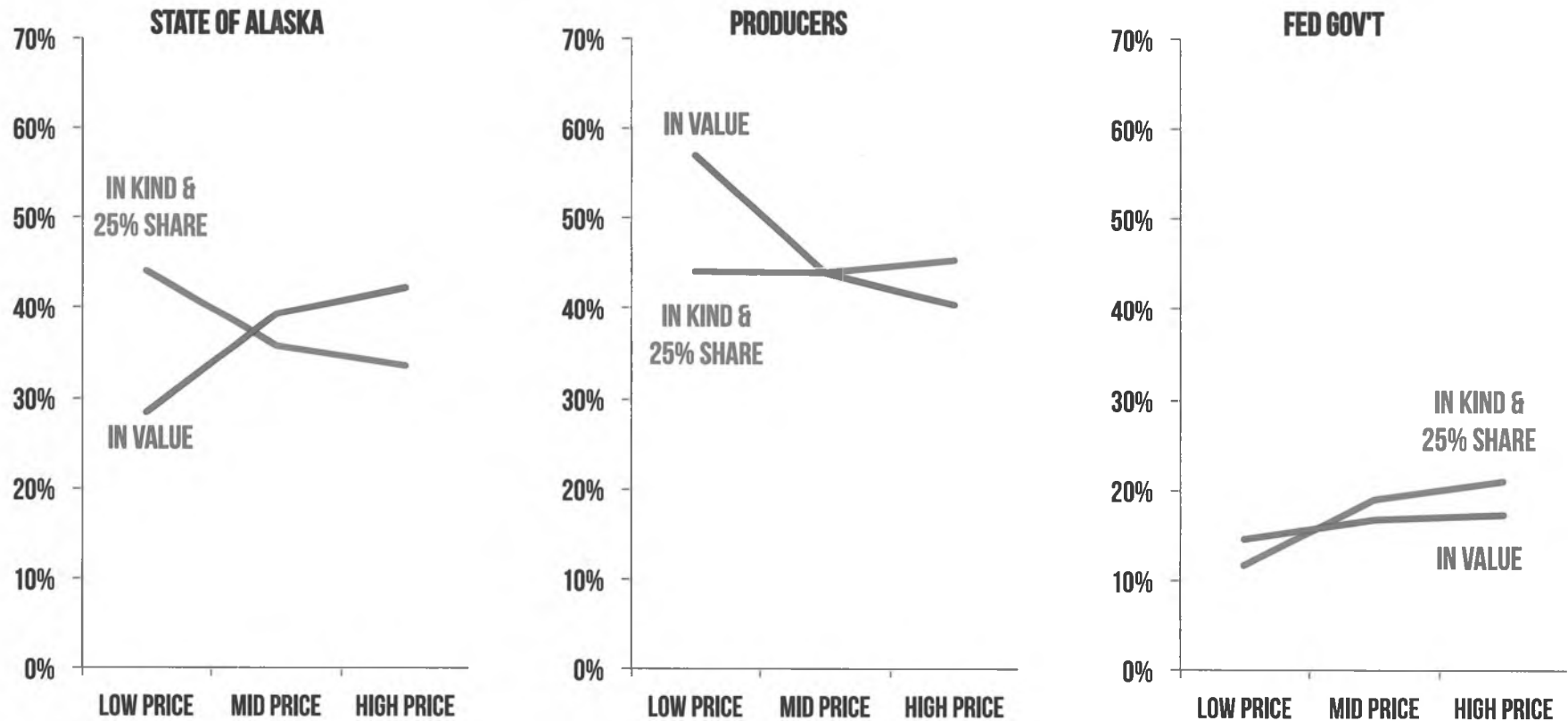


SOA SHARE OF VALUE HIGHER THAN SHARE (25%) EQUITY

SOA participation in midstream means fixed tariff for producers no longer “guaranteed”

Ability to maintain tax-exempt status is crucial to transfer value from federal government to SOA

PERCENT OF NET PRESENT VALUE OVER PROJECT LIFE



AK LNG OUT OF THE MONEY? › IN KIND VS. IN VALUE › MIDSTREAM OPTIONS › CASH EXPOSURE

project structure options › financial analysis of the TransCanada option

	<u>System</u>	<u>SOA ownership percent</u>			<u>SOA share of CAPEX & OPEX</u>			<u>SOA cash commitments</u>	
	Value / Kind	Upstream	GTP & Pipe	LNG	Upstream	GTP & Pipe	LNG	Debt	Tariffs
Status Quo	in value	0%	0%	0%	Indirect (taxes)	0%	0%	No debt	Tariff matters for valuation
HOA	in kind	0%	25%	25%	Indirect (taxes)	25%	25%	Principal and interest	Tariff only notional
MOU Option 1	in kind	0%	10% (40% x 25%)	25%	Indirect (taxes)	10% (40% x 25%)	25%	Principal and interest	Tariff payable to T/C
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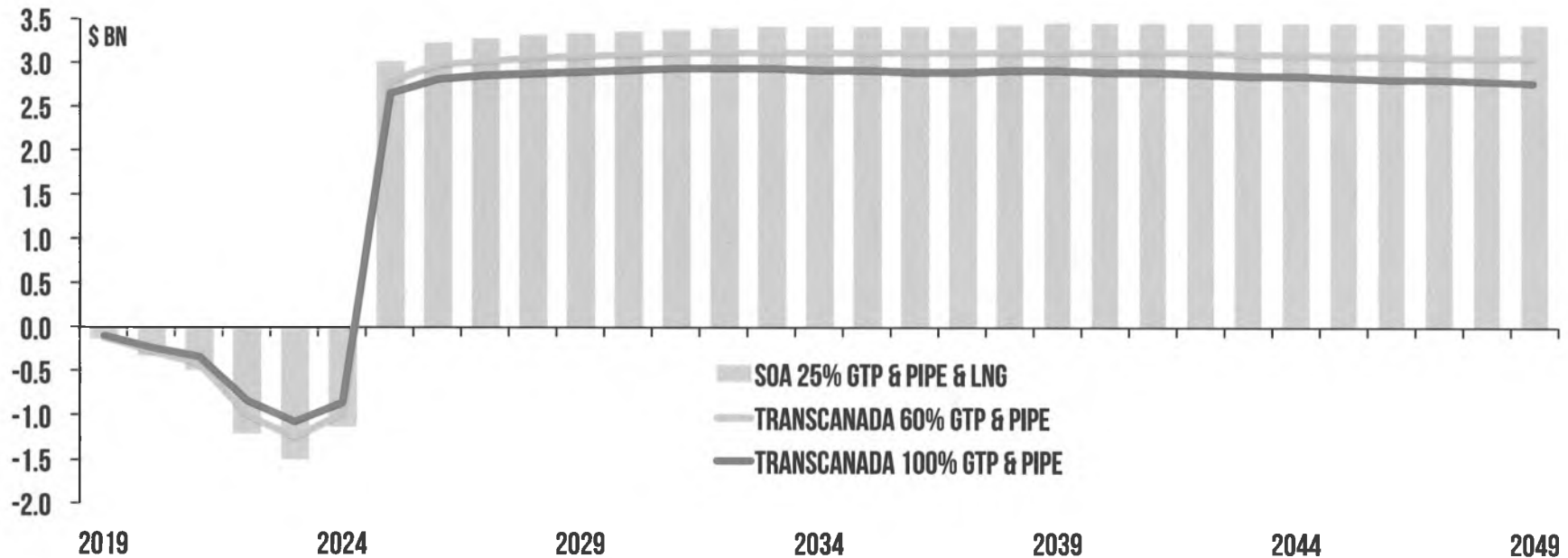
FINANCIALLY, TRANSCANADA DEAL IS AKIN TO A LOAN

TransCanada shoulders a share of SOA's capital commitments and Alaska repays over time with tariff

During construction period, SOA outlays are \$1.7 bn lower (average \$237 mm annually) on 70/30 equity

During operation period, SOA cash flows are \$522 mm lower annually (\$430-\$660 mm range)

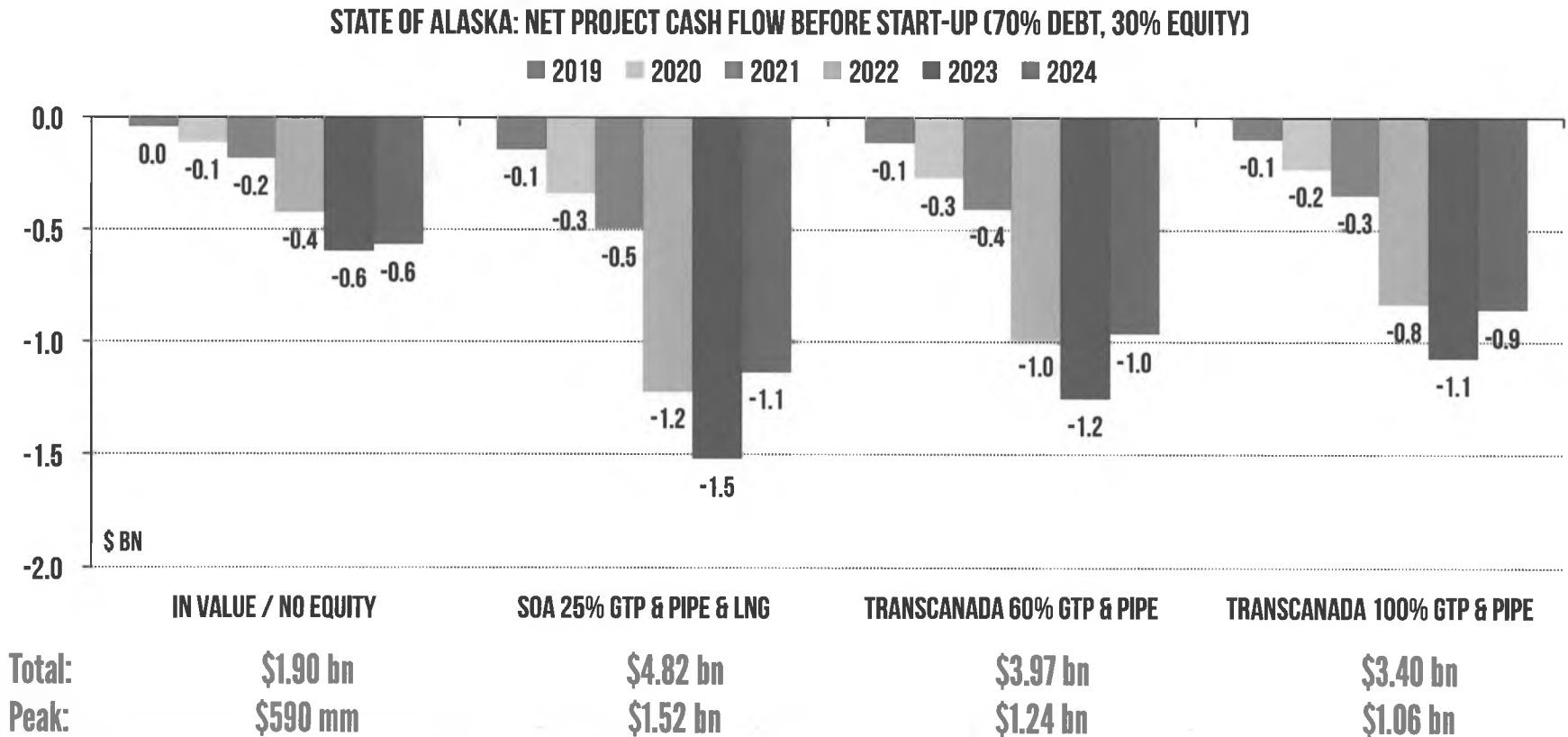
STATE OF ALASKA: CASH FLOWS FOR ALASKA LNG



SOA OUTLAYS: \$3.4–4.8 BN IN BASE CASE & 25% EQUITY

Annual outlays could peak at \$1.5 bn if SOA took 25% equity and debt-financed 70% of its share

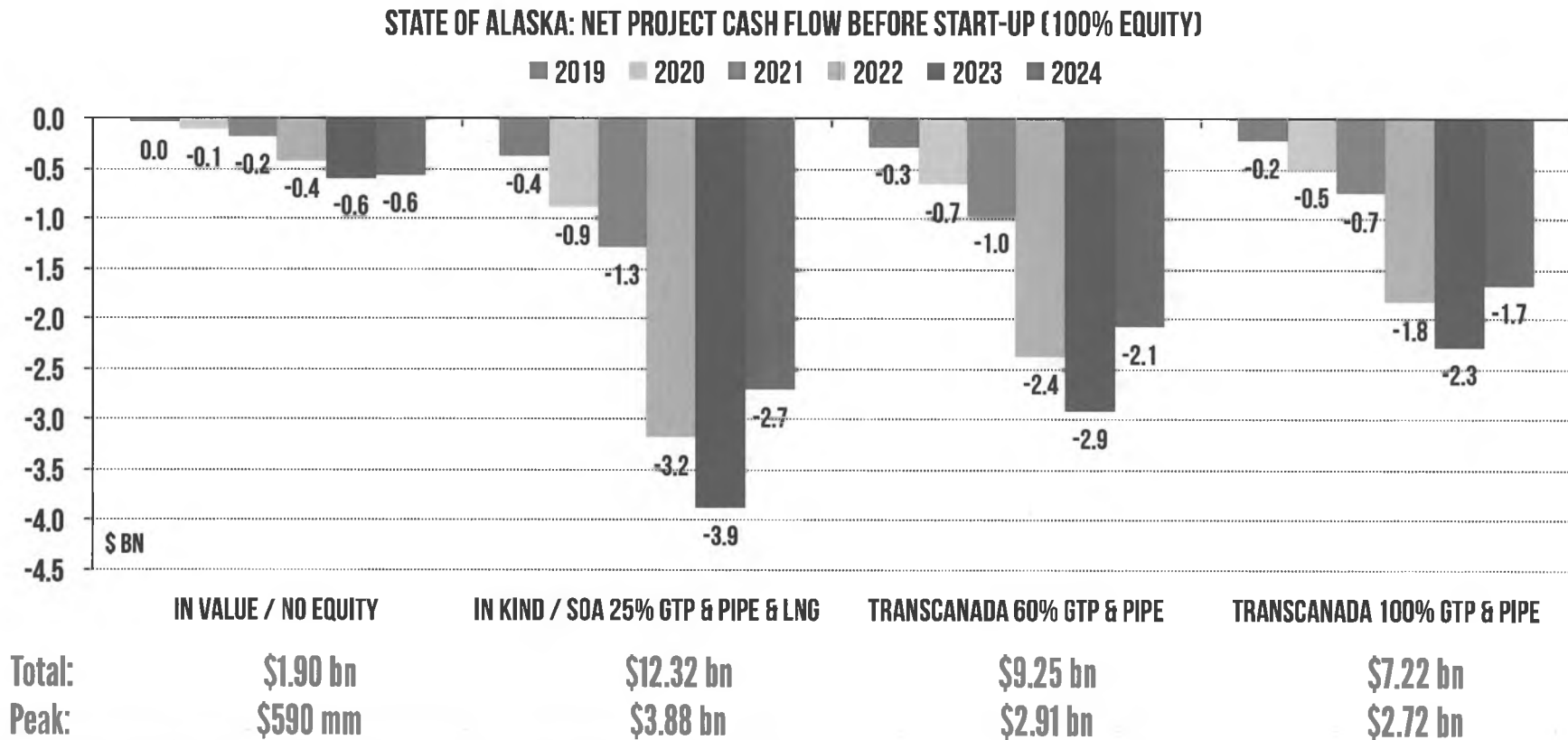
25% equity for SOA without a midstream partner is the scenario with highest outlays



100% EQUITY FINANCE PUSHES OUTLAYS TO \$12.3 BN

Annual outlays would peak at \$3.9 bn if SOA took 25% equity and financed its share with equity

Midstream partnership could reduce outlays by up to ~\$5 bn



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Growing Alaska Through Responsible Resource Development

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Senate Resources Committee on SB 138

Feb. 19, 2014

Testimony of Rick Rogers, Executive Director, Resource Development Council

Good evening madam chair and members of the committee. My name is Rick Rogers, Executive Director of the Resource Development Council. RDC is a statewide business association representing forestry, oil and gas, mining, tourism, and fishing industries. Our mission is to grow Alaska through responsible resource development. RDC supports policies aimed at increasing the commercial viability of developing Alaska's natural gas resources.

Alignment and Durability, two words that are used so much in resource policy deliberations that perhaps they become cliché. But if we are going to move forward in monetizing north-slope gas, these are both essential.

The "Heads of Agreement" aligning the interests of the three major North Slope producers (ExxonMobil, BP and ConocoPhillips), TransCanada, the State administration and the State-owned Alaska Gas line Development Corporation (AGDC) is a major step forward. This represents unprecedented alignment of interests in moving forward in developing this world-class gas resource for both in state use and export. Getting the producers, the State and TransCanada on the same page is unprecedented. With the recent announcement of the Heads of Agreement, we can see a path forward to a single project involving the producers, TransCanada and the state through a newly formed subsidiary of AGDC.

Unlike oil, LNG is sold on long-term multi-decade contracts. An LNG project will require durable and predictable fiscal terms, and the heads of agreement and authorizing SB138 provides for a stepped approach forward in defining the state's participation including fiscal terms and a corresponding equity interest.

As Alaskans we need to have a serious and deliberate conversation about Alaska's role in such a project. SB138 will require lots of work and analysis and I am impressed with the deliberate due diligence this committee is undertaking. We need to carefully weight the risks, the rewards with a realistic eye on the need to compete globally with dozens of other jurisdictions and projects hoping to secure project backing.

Rick Rogers, RDC

Testimony to Senate Resources, on SB138, February 19, 2014

Without question the most beneficial gas line project for Alaskans is a large capacity line sanctioned by the producers in partnership with the State. Fundamental project economics, largely out of our control, will dictate whether this project ever gets constructed.

To have any hope for monetizing gas, we must maintain a robust oil industry on the slope. Oil pays the bills and supports the vast and complex infrastructure on the North Slope needed to produce gas. If we fail to defeat the ballot referendum repealing SB21 in August, we signal to the producers and the world that we lack the long-term vision essential in developing our gas resources.

RDC believes alignment of interests; durable agreements including fiscal terms; and maintaining a vibrant competitive oil industry are vital to gas line development. The deliberate stepped approach to moving this project forward with an eye towards alignment and durability is our best hope for an economically viable large capacity LNG project. We also need to weigh the project risks against the risks of failure to monetize our gas.

We encourage the committee to continue with its due diligence and to pass enabling legislation this session, recognizing that this is a stepped approach with further legislative decision points and off ramps down the road as the project matures.

Thank-you for the opportunity to testify.



International Union of Operating Engineers

LOCAL 302 • Washington and Alaska • AFL-CIO

Daren Konopaski, *Business Manager and General Vice President*

Corey Baxter, *District 8 Representative*

February 19, 2014

Senate Resources Committee
Alaska State Senate
State Capitol, Room 205
Juneau, AK 99801

Re: SB 138 Alaska Gas Line

To Whom It May Concern:

The International Union of Operating Engineers Local 302 understands that SB 138 is a very complicated bill with lots of details to work out and resolve.

We would like to take this opportunity to express our willingness to stand behind a solution that protects the state's interests and benefits Alaskan's statewide.

With regard to that, we are interested in amending SB 138 to include PLA language, originally provided in the Heads of Agreement document, to help ensure future employment opportunities for Alaskan's and their families.

Thank you for all of your continuing efforts to ensure that Alaska has a productive and self-sustaining future.

Sincerely,

Corey Baxter
District 8 Representative
International Union of Operating Engineers Local 302
9309 Glacier Hwy., Suite A-105
Juneau, AK 99801
(907)586-3850
(907)463-5464 (facsimile)

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To: Senate Resources Committee Members
From: Lisa Weissler, Attorney
Date: February 19, 2014
Re: Senate Bill 138, Public Comment

As a signatory to the Heads of Agreement (HOA) for the Alaska LNG Project, the Administration has committed to incorporating the HOA principles into contracts if acceptable "Enabling Legislation" is passed by the Legislature. The enabling legislation is SB 138.

The HOA does not meet with the constitutional principle that Alaska's resources be developed consistent with the public interest.

For any pipeline project, the state's public interests remain the same. These are:

- Revenue for state public services and infrastructure
 - Revenue for communities along the pipeline route
- Gas for use in-state
- Pipeline access and expansion to encourage independent exploration and development
- Transparency
- Work commitments
- Alaska hire

If the HOA principles are incorporated into a signed contract, the state will bear the costs and responsibility for meeting the state's public interests, while the producers will have little obligation to Alaska other than giving the state a fixed percentage of produced gas.

As demonstrated by the attached matrix, many of the HOA principles match the terms of the Stranded Gas Fiscal Contract submitted to the legislature for approval in 2006. The legislature declined to approve the contract because its terms were not in the state's best interests.

Like the stranded gas fiscal contract, the HOA principles impose far too many obligations on the state, including paying billions to help advance and build the pipeline, assuming the risk of losing its investment if the project is not completed, paying the costs of treating, transporting and marketing state royalty and tax gas, providing gas for in-state use, being the sole provider of capacity for independent producers, and paying expansion costs. These are huge commitments by the state, made in exchange for nothing more than a continuation of pre-front-end engineering and design work. When a pipeline is finally built, the state will be locked into terms where no matter what the value of our natural gas, the state's share and obligations remain the same – meaning that, at high prices the producers reap a windfall, and at low prices the state's obligations could exceed its return.

Where the Stranded Gas Development Act had at least some limits and criteria to protect the state's interests in contract negotiations, SB 138 is a blank check, providing no limits to the terms the Department of Natural Resources commissioner can develop for inclusion in a contract. The HOA identifies positions the Administration has essentially already agreed to – passage of SB 138 as written would signal legislative support for these positions. The result can only be a contract that fails to serve Alaska.

Heads of Agreement Guiding Principles Compared to Stranded Gas Fiscal Contract Terms

Alaska Interests	Heads Of Agreement - 2014	Stranded Gas Fiscal Contract - 2006
<p>REVENUE</p> <p>State Ownership Past ownership studies advised the state to consider (1) that the state does not have the financial strength to absorb large losses; (2) the need to have readily available funds for calls for capital expenses; (3) that minority participation would likely result in limited management rights; (4) that the state shares the risks of cost overruns; and (5) potential conflicts between the state's sovereign duties and fiduciary obligations as a partner.</p>	<p>Article 5. Subject to passage of enabling legislation and execution of project-enabling contracts, the State's participating interest share in each component would be approximately 20% to 25%.</p>	<p>Sec. 7.2. The State shall own, directly or indirectly through State-owned entities, a 20% interest in a Gas Treatment Plant, the Mainline, and the Alaska to Alberta Project; and in Gas Transmission Pipelines.</p>
<p>Royalty Under current law, the State has the option of taking its royalty oil or gas in kind (RIK) or in value as cash (RIV). The state's decision to switch between in kind or in value can take place on fairly short notice. For a project like the gas pipeline, longer notice is needed.</p>	<p>Section 8.1. The State will take its royalty gas in kind during the duration of the contract. Sliding scale and net profit leases will be modified to a fixed percentage royalty to be taken in-kind. The State could switch to RIV but only after the initial contract term.</p>	<p>Article 12. The State would take its royalty gas in-kind throughout the life of the contract subject to specified payment methods and calculations. Sliding scale leases could be converted to a fixed royalty percentage.</p>
<p>Gas production tax Currently, the state's oil and gas production tax is paid in cash.</p>	<p>Section 8.2. The Producers have the right to elect to make gas production tax payments in gas rather than cash.</p>	<p>Article 13. The State committed to taking tax as gas rather than cash.</p>
<p>In-kind Costs Under current law, for most leases, the producer pays the costs of treating state royalty gas, including removing and disposing of impurities.</p>	<p>Section 8.3. Based on where the HOA describes delivery of the royalty and tax gas to the State, it appears the State will assume the costs associated with treating and transporting royalty and tax gas.</p>	<p>Articles 12 & 13. The State would assume the costs associated with treating and transporting royalty and tax gas, including assuming the cost for disposal of impurities.</p>
<p>Property Taxes and Impact Payments The state levies a property tax on the value of oil and gas property in the state. Oil and gas property within local government boundaries may also be taxed at the local level.</p> <p>Communities along the pipeline route are impacted during construction by increased population pressures, housing shortages, loss of local workers to pipeline jobs, and increased public safety and health care needs.</p>	<p>Section 9.3. Subject to consultation by the Administration with local governments, payments in lieu of property taxes would be on a unit rate per throughput basis and could be level or escalating dollar payments for the Alaska LNG Project components.</p> <p>The Alaska LNG Project will pay impact payments.</p>	<p>Articles 17. Payments in lieu of oil pipeline property taxes property taxes would be based on energy throughput rather than property values,</p> <p>Article 18. The Mainline Entity would pay impact payments totaling \$125 million over five years.</p>
<p>IN-STATE MARKETS An anticipated benefit to the state in having a natural gas pipeline is getting gas to meet local power needs.</p>	<p>Section 6.5. Five in-state offtake points would be included as part of the project; third-parties will have to pay for any facilities taking gas from an offtake point. Any Party may deliver gas to an offtake point. Third-party gas must meet certain criteria.</p>	<p>Article 9. Four in-state offtake points were part of the project; third-parties would have to pay for any facilities taking gas from an offtake point. Any Party may sell gas to an Alaska purchaser; no Party is required to sell gas to an Alaska purchaser.</p>

Heads of Agreement Guiding Principles Compared to Stranded Gas Fiscal Contract Terms

Alaska Interests	Heads Of Agreement - 2014	Stranded Gas Fiscal Contract - 2006
<p>ACCESS & EXPANSION Robust exploration and development of state oil and gas resources requires that all gas producers, large and small, have capacity to ship gas in the pipeline and that transportation rates are not a barrier to new explorers and developers.</p> <p>When a pipeline is filled to capacity, it can be expanded. Expansion for an LNG project is complicated and expensive because different shipping contracts require different gas weights, and so expansions could require the addition of a new LNG processing facility (liquefaction train).</p>	<p>Section 6.3 and Appendix A. Access and expansion will be developed consistent with the regulatory framework under the Natural Gas Act, Section 3. The State portion of the project will be responsible for providing capacity access to the pipeline for independent producers, for both in-state and export gas; the Producer capacity will be private; and expansion costs will be borne by whoever requests the expansion.</p>	<p>Article 8. Regulation of and access to the project (including expansion) will be governed and controlled exclusively by the Natural Gas Act, Alaska Natural Gas Pipeline Act of 2004 [applicable to an overland pipeline], other applicable federal law and the contract. The State could initiate expansions, but only after meeting multiple hurdles, including that the State must not require existing shippers to pay a higher rate than without an expansion; and expansion would be available only every 5 years.</p>
<p>Transparency State participation in the pipeline can create a conflict between the public's right to know the basis for its government's decisions and the state's fiduciary responsibility as a pipeline partner to keep project information confidential.</p>	<p>Section 7.2. The Administration will submit proposed general legislation to provide for a confidential process to develop terms for project-enabling contracts.</p> <p>- SB 138 would authorize the DNR commissioner to enter confidentiality agreements to maintain the confidentiality of information related to contract negotiations and contract implementation.</p>	<p>Article 29. Established how confidential information and material could be used and disclosed.</p> <p>- The Stranded Gas Development Act provided specific terms and conditions for confidentiality and disclosure of information during the course of contract negotiations; and established public disclosure requirements upon issuance of a preliminary findings and determination.</p>
<p>Work Commitments It is important to the state that a pipeline advances through to completion, particularly if the state makes a substantial investment in progressing the pipeline.</p>	<p>Article 4. The Alaska LNG Parties will continue Pre-FEED work through to completion with the passage of "Enabling Legislation," execution of a new commercial agreement, and progress on other support referenced in Sec. 10. Decisions to advance to the FEED phase are subject to enabling legislation and other laws, including necessary fiscal and commercial terms.</p>	<p>Section 5.2. Participants would advance the Project planning activities by Diligence and conclude these activities with a decision on whether to begin preparation of regulatory applications for an Open Season. "Diligence" means advancing the Project as diligently as is prudent under the circumstances.</p>
<p>Alaska Hire A benefit to Alaska of a pipeline project is jobs for Alaskans. The federal constitution precludes an absolute requirement that Alaskans be hired first.</p>	<p>Article 11. Within the constraints of law, the LNG Parties will employ Alaska residents and contract with Alaska business to the extent they are qualified, available, ready, willing, and cost competitive. Prior to construction, the Parties commit to negotiate in good faith project labor agreements for the LNG Project.</p>	<p>Section 6.2. Within the constraints of law, the Midstream entity would employ Alaska residents or contract with Alaska businesses to the extent they are available, ready, willing and qualified, and competitively priced in that they offer goods or services at a total cost equal to or less than the total cost of equivalent goods or services offered by a non-Alaska resident or business.</p>

From: Jerry Dewhurst
Sent: Wednesday, February 19, 2014 12:57 PM
To: LIO Anchorage
Subject: SB 138

Dear Committee Members:

I encourage you to move forward toward building a pipeline which will provide Alaska natural gas to Alaskans and if possible export it for profit elsewhere in the World.

Gerald Dewhurst

PO Box 242744

Anchorage, Ak 99524

Jerry Dewhurst

Office: 257-0113

RE/MAX Properties, Inc

110 W 38th Ave #100

Anchorage AK 99503



International Union of Operating Engineers LOCAL 302 • Washington and Alaska • AFL-CIO

Daren Konopaski, *Business Manager and General Vice President*

Corey Baxter, *District 8 Representative*

February 19, 2014

Senate Resources Committee
Alaska State Senate
State Capitol, Room 205
Juneau, AK 99801

Re: SB 138 Alaska Gas Line

To Whom It May Concern:

The International Union of Operating Engineers Local 302 understands that SB 138 is a very complicated bill with lots of details to work out and resolve.

We would like to take this opportunity to express our willingness to stand behind a solution that protects the state's interests and benefits Alaskan's statewide.

With regard to that, we are interested in amending SB 138 to include PLA language, originally provided in the Heads of Agreement document, to help ensure future employment opportunities for Alaskan's and their families.

Thank you for all of your continuing efforts to ensure that Alaska has a productive and self-sustaining future.

Sincerely,

Corey Baxter
District 8 Representative
International Union of Operating Engineers Local 302
9309 Glacier Hwy., Suite A-105
Juneau, AK 99801
(907)586-3850
(907)463-5464 (facsimile)

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February 11, 2014

Governor Sean Parnell
State of Alaska
P.O. Box 110001
Juneau, Alaska 99811-0001

Dear Governor Parnell:

As local government leaders, we are encouraged by the prospect of construction of a natural gas pipeline. We support continued efforts toward completion of a successful project and the economic benefits it will bring to the State of Alaska, our communities and our residents.

We would be remiss in our responsibilities, however, if we did not express our growing concerns about the potential impacts to local governments. Our individual taxing structures and tax bases provide the revenues necessary to pay for local government services. In that respect, we have become concerned about the lack of information provided to municipalities regarding the impacts of the ongoing negotiations, particularly local government concessions that may be considered during pending gas pipeline negotiations with the North Slope producers.

The Heads of Agreement between the State of Alaska, North Slope producers and TransCanada provides the parties will negotiate fiscal concessions before undertaking an additional study of a gas pipeline project. The agreement states one of its purposes is to reduce valuation disputes between the parties, and to ensure a healthy long-term oil business. We are concerned that these terms might alter property taxes paid on existing infrastructure, including that used in oil exploration, production and transportation. The municipalities wish to be assured that the terms of a fiscal deal on the gas pipeline will not impact taxes on existing property.

We recognize there may be a need for agreements on fiscal terms to help facilitate a successful project. We are willing to be party to such agreements provided that we have the opportunity to participate in the discussions and to negotiate and agree to terms that directly impact municipal tax structure and revenues. The terms of any agreement will extend well beyond our tenure in elected office. We have a responsibility to understand, analyze and evaluate, in depth, the impacts and consequences as they relate to the State of Alaska, our communities and residents - including future generations.

We have joined together in this effort, and are hopeful that you and your administration will not only engage in "consultation" with the municipalities, but will allow us to meaningfully participate. We look forward to counting on your support and are hopeful you will work with us to ensure that municipalities affected by the gas pipeline directly participate in the discussions and negotiations on decisions that will impact our communities.

Sincerely,



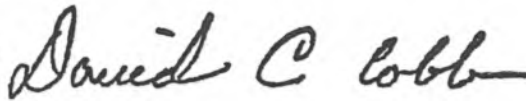
Mayor Luke Hopkins
Fairbanks North Star Borough



Mayor Mike Navarre
Kenai Peninsula Borough



Mayor Charlotte Brower
North Slope Borough



Mayor Dave Cobb
City of Valdez

Cc: House Speaker Mike Chenault
Senate President Charlie Huggins

**ConocoPhillips Alaska
Senate Resources Committee
SB138 – February 12, 2014**

Madame Chair, members of the committee, for the record my name is Pat Flood. I supervise the North Slope gas development team for ConocoPhillips in Anchorage.

ConocoPhillips appreciates the opportunity to testify today in support of SB138.

Last week I came before you to discuss the Heads of Agreement and said that ConocoPhillips believes there are four key areas where it is important to get legislative input to continue advancing the project as envisioned in the Heads of Agreement:

1. The state must decide that it wants to participate in the project.
2. The state needs to decide what share of the gas the state would have, which would set the state's participation share.
3. The legislature needs to define a production tax (taken as gas molecules), which, with the existing state royalty (also taken as gas molecules) would provide the state's overall gas share that would support the state participation share.
4. The legislature needs to give the administration the necessary tools to confidentially work through all the various arrangements and contracts required to move the project ahead as is outlined in the Heads of Agreement.

We think that, overall, the proposed legislation, as general law, effectively addresses these key areas.

In their sectional analysis this past Friday the administration broke the proposed legislation into three groups of sections, the first group dealt with AGDC's scope, powers and structure. The second group dealt with the DNR commissioner's powers and duties with respect to contract negotiations and oil and gas leases; and the third group dealt with the tax statutes.

In our testimony today we'll address our comments in the same three groups.

The first group of sections in the bill address AGDC and its potential role with regard to an LNG project. ConocoPhillips supports AGDC managing the State's participation share in an LNG project. We realize that there are ongoing legislative discussions about the structure being proposed. Ultimately, the details of AGDC's structure and authority are a decision for the state. We simply support AGDC as a viable way for the state to participate in an LNG project.

The second group of sections in Title 38 relate to the DNR commissioner's flexibility with respect to negotiating changes to the oil and gas leases from which gas could be

committed to a larger project, and for the myriad other agreements that would be required in order to progress an LNG project and manage the state's role in such a project. The LNG business, as your consultants have told you, requires numerous contracts covering nearly all the aspects of the value chain. For the state to effectively participate in a large natural gas project, such as an LNG project, with other private co-venturers the commissioners of both DNR and DOR need to be able to negotiate, confidentially, the details of these many agreements in a way that doesn't compromise the commercial positions.

We believe the commissioners need this authority in order for the state to effectively participate in a project with other parties.

The final set of sections deals with the tax statutes in Title 43. These provisions set a fixed gross value production tax at 10.5%, with the ability of the state to accept payment of this tax in gas molecules. Effectively, the choice of the tax rate, when combined with the existing royalty percentage, would set the state gas share for participation in a natural gas project such as the LNG project contemplated in the Heads of Agreement.

ConocoPhillips does support the provisions that allow for a fixed gross production tax, payable in gas. The 10.5% rate the administration has proposed yields a combined royalty plus production tax in the range of the 20-25% that is in the Heads of Agreement..

Overall, Madame Chair, ConocoPhillips supports the legislation, recognizing that it contains some significant policy decisions the legislature needs to make when contemplating the state's role in a large natural gas project, including the LNG project contemplated in the Heads of Agreement.

To the extent that we can help you by providing information or perspectives on those issues we're happy to do so.

Thank you, Madame Chair, for the opportunity to testify today. We are available to try to answer any questions you, or the committee, may have.

From: Jerry Dewhurst
Sent: Wednesday, February 19, 2014 12:57 PM
To: LIO Anchorage
Subject: SB 138

Dear Committee Members:

I encourage you to move forward toward building a pipeline which will provide Alaska natural gas to Alaskans and if possible export it for profit elsewhere in the World.

Gerald Dewhurst

PO Box 242744

Anchorage, Ak 99524

Jerry Dewhurst

Office: 257-0113

RE/MAX Properties, Inc

110 W 38th Ave #100

Anchorage AK 99503

January 14, 2014

HEADS OF AGREEMENT

By and Among

**THE ADMINISTRATION OF
THE STATE OF ALASKA**

**ALASKA GASLINE
DEVELOPMENT CORPORATION**

TRANSCANADA ALASKA DEVELOPMENT INC.

EXXONMOBIL ALASKA PRODUCTION INC.

CONOCOPHILLIPS ALASKA, INC.

BP EXPLORATION (ALASKA) INC.

FOR THE ALASKA LNG PROJECT

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THIS HEADS OF AGREEMENT is made this 14th day of January, 2014 (“Effective Date”) by and among:

- (1) The Administration of the State of Alaska, by and through the Commissioner of the Department of Natural Resources (“DNR”) and the Commissioner of the Department of Revenue (“Administration” or “Commissioners”);
- (2) Alaska Gasline Development Corporation (“AGDC”);
- (3) TransCanada Alaska Development Inc. (“TADI”);
- (4) ExxonMobil Alaska Production Inc. (“EMAP”);
- (5) ConocoPhillips Alaska, Inc. (“ConocoPhillips”); and
- (6) BP Exploration (Alaska) Inc. (“BP”).

The Administration, AGDC, TADI, EMAP, ConocoPhillips, and BP may hereinafter be collectively referred to as the “Parties” and separately as a “Party”. TADI, EMAP, ConocoPhillips, and BP (and their respective Affiliates participating in the Alaska LNG Project) and AGDC are collectively referred to as the “Alaska LNG Parties” and EMAP, ConocoPhillips and BP (and their respective upstream Alaska Affiliates) are collectively referred to as the “Producer Parties”.

RECITALS

- (A) Each of the Producer Parties owns natural gas resources on the Alaska North Slope and each Producer Party has explored and pursued, individually and jointly, various means of bringing ANS natural gas to market in previous projects, including the Alaska Natural Gas Transportation System project, liquefied natural gas export projects, gas-to-liquids conversion projects, the Alaska Gas Producers Pipeline Team project, the Denali Gas Pipeline project and the Alaska Pipeline Project.
- (B) The Parties are currently undertaking work to evaluate a project to potentially commercialize ANS natural gas resources through the Alaska LNG Project (as that term is defined below). The Administration and AGDC believe that the Alaska LNG Project may provide an opportunity for AGDC to provide gas to Alaskans at the lowest possible cost.
- (C) In October 2011, in response to changed circumstances, including a substantial increase in U.S. shale gas reserves in the Lower 48 states, Governor Parnell requested the Licensee under the Alaska Gasline Inducement Act (“AGIA”) to work cooperatively with the Producer Parties to evaluate the economic feasibility of an LNG alternative, which would include LNG export volumes and the opportunity for deliveries of in-state gas. The Licensee (an Affiliate of TADI) had previously (with an Affiliate of ExxonMobil) been focused on a project to transport Alaska gas to Alberta for further delivery to North American markets.

- (D) In January of 2012, the CEOs of ExxonMobil, BP and ConocoPhillips met with Governor Parnell and on March 30, 2012, the CEOs issued a letter informing the Governor of their progress and planned activities in pursuit of an LNG export project utilizing ANS gas resources, which would also provide the opportunity for in-state gas deliveries, and noting the importance of establishing appropriately structured and stable fiscal arrangements (see Exhibit I-A).
- (E) In October of 2012, ExxonMobil, BP, ConocoPhillips and TADI informed the Governor of the significant early efforts to progress what is now known as the Alaska LNG Project, including the establishment of an integrated team with specialized skills to further pursue and advance the work. Numerous potential options to commercialize the ANS gas resources were analyzed due to the complex nature of developing the vast ANS gas resources. The letter also described the challenges facing development of the Alaska LNG Project and the need for a healthy, long-term oil business, underpinned by a competitive fiscal framework (see Exhibit I-B).
- (F) In February of 2013, the Producer Parties and TADI agreed on a concept for the potential Alaska LNG Project and began to undertake initial Pre-FEED activities which is an important and substantial step in major project developments. Those Parties are currently considering ramping up Pre-FEED activities (see Exhibit I-C).
- (G) The Alaska LNG Parties are currently negotiating commercial agreements for Pre-FEED to move to the next phase of the Alaska LNG Project based on the concept development and successful 2013 summer field season work performed by the Producer Parties and TADI.
- (H) Funding by the State of Alaska ("State") under AGIA has supported some key activities including the 2013 summer field season. Now that it is evident that an LNG export project (along with the opportunity for in-state delivery of gas), rather than a pipeline to Alberta, Canada, is the leading case to commercialize ANS gas resources, the Administration, the AGIA Licensee and TADI have concluded that it is appropriate to transition from the AGIA license and to focus efforts on the Alaska LNG Project.
- (I) In 2013, the Legislature passed and Governor Parnell signed legislation for AGDC to pursue an in-state gas pipeline, the Alaska Stand Alone Pipeline ("ASAP") project. The Administration and AGDC intend that AGDCS would participate in the Alaska LNG Project, and AGDC would establish membership on the board of AGDCS which may include the Commissioners, to the extent permitted by law. The Administration also intends to seek funding for AGDC (or AGDCS, when formed) participation in the Alaska LNG Project. AGDC will also continue to pursue the ASAP project. AGDC and the Alaska LNG Parties intend to cooperate with one another on technical and engineering matters to achieve efficiencies and share technical data to effectively manage resources.
- (J) The Alaska LNG Parties wish to ramp up the Pre-FEED phase of the Alaska LNG Project, which is estimated to cost over \$400 million, but are seeking understandings with the State concerning the State's and the Producer Parties' desire for State participation in the Alaska

LNG Project, consistent with certain fiscal and commercial principles described in this HOA, prior to ramping up the Pre-FEED phase. Similarly, the Administration is seeking understandings from the Alaska LNG Parties to advance the Alaska LNG Project.

- (K) The Administration has determined that State participation in the Alaska LNG Project could yield significant overall benefits for the State. The Parties recognize that enabling legislation to facilitate State participation in advancing an LNG export project to develop Alaska gas resources is desirable.
- (L) The Producer Parties and the Administration have developed guiding objectives to progress the Alaska LNG Project, which include creating an environment to: (a) enable the Alaska LNG Project to be completed in an expedited and reasonable fashion; (b) maximize the value of ANS resources to the State, Producer Parties and other stakeholders; and (c) expand the contribution of ANS resource development to Alaska's economic growth.
- (M) The Parties have entered into discussions as to how they may cooperate with each other to jointly pursue the Alaska LNG Project. Accordingly, this HOA establishes certain guiding principles and understandings to support advancement of the Alaska LNG Project and that would lead to important commercial and operating arrangements between the Parties.

NOW, THEREFORE, the Parties agree as follows:

ARTICLE 1: DEFINITIONS

1.1. *"Affiliate"* means,

- a. In relation to TADI or a Producer Party, any company, corporation, partnership or other legal entity (in this definition, each such entity and each Party are sometimes referred to as a "Company"), that:
 - (i) Is directly or indirectly owned or controlled by such Party;
 - (ii) Directly or indirectly owns or controls such Party; or
 - (iii) Is directly or indirectly, owned or controlled by a Company that also, directly or indirectly, controls such Party; and
- b. In relation to AGDC, those State entities that otherwise meet the requirements of the definition above, when acting only in the State's proprietary capacity, including other independent State corporations.

For the purpose of this definition, a Company is directly owned or controlled by another Company that owns or controls shares or other interests carrying in the aggregate more than 50 percent of the voting rights exercisable at a general, shareholders, or members meeting of the first-mentioned Company, or the right to appoint or dismiss a majority of the directors thereof, or the power to direct or cause the direction of the management or policies through the ownership of securities, by contract or otherwise. A Company is indirectly owned or controlled by a

Company or Companies (the “parent Company or Companies”) if a series of Companies can be specified, beginning with the parent Company or Companies and ending with the particular Company, so related that each Company of the series, except the parent Company or Companies, is directly controlled by one or more of the Companies in the series.

1.2. “*AGDC*” means the Alaska Gasline Development Corporation as set forth in AS 31.25.

1.3. “*AGDCS*” means a wholly-owned subsidiary of AGDC to be formed for the specific purpose of participating in the Alaska LNG Project.

1.4. “*Alaska LNG Project*” means, collectively, the project components consisting of the LNG Plant, the Gas Pipeline, the Gas Treatment Plant, the PBU Gas Transmission Line, and the PTU Gas Transmission Line.

1.5. “*Alaska North Slope*” or “*ANS*” means that part of Alaska that lies north of 68 degrees North latitude.

1.6. “*Enabling Legislation*” means legislation enacted by the Alaska Legislature that has become effective as provided in AS 01.10.070, and that at a minimum:

- a. Provides for a confidential process that would allow the Administration to participate in developing terms for contracts associated with a project, including but not limited to (1) project-enabling contracts, which contracts are subject to subsequent legislative ratification, (2) the front-end engineering and design work agreements and (3) other project implementation contracts; and
- b. Allows for contract terms which could include terms that address: State participation; a State share of gas (royalty in kind and gas in lieu of production taxes); property taxes; upstream costs and lease expenditures; in-state gas deliveries; ownership interests; operating agreements; gas treatment, transportation, and liquefaction services agreements; State LNG or gas sales contracts; contract duration and durability; periodic project reporting; Alaska hire; Alaska contracting; and other terms necessary to advance projects to commercialize Alaska’s natural gas resources.

1.7. “*FEED*” means a front-end engineering and basic engineering design study, which, without limitation, would include the following:

- a. Sufficiently detailed basic engineering packages for the components of the Alaska LNG Project and a contracting strategy to enable contractor bidding for the Engineering, Procurement and Construction (“EPC”) contracts;
- b. A resourcing, commissioning and start-up plan;
- c. The finalization of the key project agreements required to implement the Alaska LNG Project;
- d. A technical and commercial definition of the Alaska LNG Project;

- e. A detailed update of the Alaska LNG Project economics, financing and commercial assumptions, including an updated estimate of capital costs sufficient for a final investment decision;
- f. A final assessment of environmental, social and health impacts of the Alaska LNG Project;
- g. Long-lead procurement activities;
- h. Other activities necessary to enable a final investment decision to be taken by the Alaska LNG Parties such as but not limited to financing, permitting and registration; and
- i. The bidding and internal selection of EPC contractors, as applicable.

The detailed work plan and deliverables of FEED will be developed during Pre-FEED.

1.8. "**FEED Agreement**" means the agreement or agreements under which FEED would be undertaken for the Alaska LNG Project.

1.9. "**FERC**" means the Federal Energy Regulatory Commission.

1.10. "**Gas Pipeline**" means the Alaska LNG Project component consisting of a main natural gas pipeline from the outlet flange of the GTP on the Alaska North Slope to the inlet flange of the LNG Plant, including the structures, equipment, underlying land rights and all other associated systems, but excluding any other gas pipelines taking gas from any Offtake Point.

1.11. "**Gas Treatment Plant**" or "**GTP**" means the Alaska LNG Project component consisting of facilities, including the structures, equipment, underlying land rights and all other associated systems and related activities to receive natural gas from the PBU Gas Transmission Line, the PTU Gas Transmission Line, or other facilities, treat the natural gas to pipeline quality specifications, dispose of or deliver by-products, deliver liquid products for further transportation, and deliver treated natural gas for transportation through the Gas Pipeline.

1.12. "**HOA**" means this Heads of Agreement, including its Recitals and Appendix A.

1.13. "**Initial Project Term**" has the meaning provided in Section 9.2.

1.14. "**Joining Party**" has the meaning provided in Section 13.6.

1.15. "**Licensee**" means, collectively, TransCanada Alaska Company, LLC, a Delaware limited liability company, and Foothills Pipe Lines Ltd.

1.16. "**LNG**" means any hydrocarbon or mixture of hydrocarbons consisting predominantly of methane in a liquid state at or below its boiling point at a pressure of approximately one atmosphere.

- 1.17. **"LNG Plant"** means the Alaska LNG Project component consisting of an LNG plant facility, including the structures, equipment, underlying land rights and all other associated systems, for pre-processing and liquefaction of natural gas, and storage and off-loading of liquefied natural gas, including terminal facilities and auxiliary marine vessels.
- 1.18. **"MOU"** has the meaning provided in Section 5.4.
- 1.19. **"NGA Section 3"** has the meaning provided in Section 6.1.
- 1.20. **"Offtake Point(s)"** has the meaning provided in Section 6.5.
- 1.21. **"PBU Gas Transmission Line"** means the Alaska LNG Project component consisting of a natural gas transmission line from the outlet flange of the Prudhoe Bay Unit Central Gas Facility to the inlet flange of the GTP including the structures, equipment, underlying land rights and all other associated systems.
- 1.22. **"PILT"** means a payment in lieu of property tax as set forth in Section 9.3.1.a.
- 1.23. **"Pre-FEED"** means pre-front-end engineering and design work and activities on the approved concept in preparation for FEED for the Alaska LNG Project, including technical and execution studies and optimization and FEED / EPC invitation to tender development including sufficient design detail and environmental field work to support FERC applications and filings.
- 1.24. **"PTU Gas Transmission Line"** means the Alaska LNG Project component consisting of a natural gas transmission line from the outlet flange of the Point Thomson Unit production facility to the inlet flange of the GTP including the structures, equipment, underlying land rights and all other associated systems.
- 1.25. **"RIK"** means royalty in kind as provided in Section 8.1.1.
- 1.26. **"RIV"** means royalty in value as provided in Section 8.1.1.
- 1.27. **"State Gas Share"** means, collectively, the State's share of RIK gas and Tax as Gas as provided in Section 8.3.
- 1.28. **"Tax as Gas" or "TAG"** has the meaning provided in Section 8.2.
- 1.29. **"Transfer"** means any sale, assignment, contribution or other disposition (a) by an Alaska LNG Party of all or part of its participating interests in the Alaska LNG Project or (b) by an Alaska LNG Party or its Affiliates of all or part of its rights and obligations in any ANS lease from which gas would be produced into the Alaska LNG Project, to a transferee (including without limitation by merger or consolidation).
- 1.30. **"Transmission Lines"** means the Alaska LNG Project components consisting of the PBU Gas Transmission Line and the PTU Gas Transmission Line.

ARTICLE 2: PRINCIPLES

2.1 This HOA sets out the guiding principles upon which the Parties wish to progress work for evaluation of the Alaska LNG Project. It is understood and agreed that if the Legislature passes Enabling Legislation that is acceptable to the Parties, the Parties would negotiate contracts, which would incorporate the principles contained in Articles 5 through 12. In entering into this HOA, it is the intent of the Parties that this HOA provide Alaskans with a roadmap for how the Parties intend to advance the Alaska LNG Project.

ARTICLE 3: BENEFITS OF THE ALASKA LNG PROJECT

3.1 A successful Alaska LNG Project would provide substantial benefits to the State, Alaska LNG Parties, and other stakeholders, including, but not limited to:

- a. The opportunity for competitively priced, reliable in-state gas supply;
- b. Commercialization of ANS gas resources through the sale of LNG to global markets and access for in-state gas demand;
- c. Creating jobs for Alaskans in the exploration, development, production and transportation of natural gas;
- d. Increased opportunities for Alaska-based contractors;
- e. Additional revenues to the State and Alaska LNG Parties; and
- f. Infrastructure for development of onshore and offshore state and federal lands to enhance Alaska oil and gas exploration and production opportunities for the Producer Parties and other explorers and producers.

ARTICLE 4: ALASKA LNG PROJECT WORK

4.1 Execution of the Alaska LNG Project involves a phased development process. To date, one or more of the Alaska LNG Parties have accomplished certain work, and the Alaska LNG Project is poised to ramp up the Pre-FEED phase. The purpose of Pre-FEED is to progress technical work that would provide each of the Alaska LNG Parties with sufficient information for evaluating the technical, cost and schedule aspects of the Alaska LNG Project. The Pre-FEED work, when used with other information regarding the commercial, legal, economic, financial, marketing, timing and other necessary aspects of the Alaska LNG Project, will assist the Alaska LNG Parties in determining how to proceed with the phased project development process, including whether to proceed to the FEED phase of the Alaska LNG Project. The FEED phase would involve the expenditure of billions of dollars to progress the Alaska LNG Project to the final investment decision ("FID").

4.2 Subject to the Alaska LNG Parties executing a new commercial agreement for ramping up Pre-FEED work, the Alaska LNG Parties will continue that work through completion,

provided Enabling Legislation acceptable to the Parties is passed and other support referenced in Article 10 is maintained or progressed. The Pre-FEED work is expected to ramp up in the second quarter of 2014, and is anticipated to take between 18 and 24 months to complete, with a determination on proceeding to the FEED phase expected to occur within approximately 36 months after ramp up of Pre-FEED. During Pre-FEED, the Alaska LNG Parties will continue to provide regular Alaska LNG Project updates to the Administration, the Alaska Legislature and the public.

4.3 Upon completion of Pre-FEED deliverables for the Alaska LNG Project, the Alaska LNG Parties will decide whether to proceed with FEED for the Alaska LNG Project. Each Alaska LNG Party will make that decision in its sole discretion.

4.4 A decision by the Alaska LNG Parties to advance the Alaska LNG Project to FEED is subject to, among other things:

- a. Enabling Legislation and other laws and regulations of the State to advance the Alaska LNG Project, including necessary fiscal and commercial terms as set forth in this HOA;
- b. Approval by the management or approving authority of the Parties, as applicable;
- c. Determination of Alaska LNG Project component sizing, gas quality specifications, and expansion terms; and
- d. Execution of contracts as contemplated by Section 7.4, as well as gas treatment, transportation, and liquefaction services agreements, and the execution of the FEED Agreement.

4.5 During the Pre-FEED phase, each of the Producer Parties and the State would initiate preliminary, individual LNG or gas sales or shipping efforts. During the FEED phase, each of those Parties would seek to execute individual LNG (or gas) sales and shipping agreements.

4.6 During the Pre-FEED phase, the Parties would work to develop mutually agreeable gas offtake and balancing agreements to facilitate gas offtake by each of the Parties with regard to their rights to capacity in the Alaska LNG Project.

ARTICLE 5: STATE PARTICIPATION IN THE PROJECT

5.1 The Administration has determined that State participation in the Alaska LNG Project could yield significant overall benefits for the State, including:

- a. Protecting the State's mineral interests and maximizing the value of its resources;
- b. Improving alignment of interests between the State and the Producer Parties;

- c. Transparency for the Administration (when acting in its proprietary capacity in regards to the State Gas Share, and with relevant confidentiality protections) regarding the Alaska LNG Project;
- d. Access and pro-expansion principles for the Alaska LNG Project;
- e. Creating an opportunity for delivering gas to Alaskans;
- f. An opportunity for additional State revenues; and
- g. Reducing valuation and other potential disputes between the Producer Parties and the State.

5.2 The Producer Parties believe that State participation in key aspects of the Alaska LNG Project, including its investment and sharing of other costs, in balance with a share of gas from the Alaska LNG Project, is a significant enabler of a successful project of that size and complexity. Accordingly, the Producer Parties support State participation in the Alaska LNG Project.

5.3 Subject to the passage of Enabling Legislation and execution of project-enabling contracts, including satisfactory arrangements for disposition of the State's share of LNG, the State would participate in the Alaska LNG Project at a participating interest share in the Alaska LNG Project components consistent with the State Gas Share in those components. The Parties anticipate the State's participating interest share in each component would be approximately 20% to 25%.

5.4 The Administration intends to enter into project implementation agreements with one or more parties to hold the State's participating interest in the Alaska LNG Project, which could include TADI and AGDC, recognizing that the Administration has entered a memorandum of understanding ("MOU") with TADI and certain of its Affiliates. The Administration, with the concurrence of TADI and certain of its Affiliates, plans on publicly releasing the MOU contemporaneously with the public release of this HOA.

5.5 During the Pre-FEED phase, the Producer Parties, TADI, and AGDC (including representatives of the Administration when those representatives are acting in a proprietary capacity in regard to the State Gas Share, and with relevant confidentiality protections) would negotiate in good faith to enter into the agreements for FEED for the Alaska LNG Project. To support those negotiations, the Alaska LNG Parties would provide for reasonable disclosure of information related to the State's participating interest in the Alaska LNG Project to representatives of the Administration when those representatives are acting in a proprietary capacity in regard to the State Gas Share, and with relevant confidentiality protections.

5.6 The Alaska LNG Parties support the principle of providing access to information related to the components of the Alaska LNG Project in which that Alaska LNG Party has an ownership interest or, prior to ownership being established, a participating interest. With respect to AGDC, access to information would include access for those representatives of the Administration associated with AGDC when those representatives are acting in a proprietary capacity in regard to the State Gas Share, and with relevant confidentiality protections. Disclosure of such

information would be in accordance with applicable law, subject to relevant confidentiality protections and sufficient to allow each Alaska LNG Party to meet its reasonable business needs, including obligations to customers, in respect of the Alaska LNG Project. The Alaska LNG Parties would negotiate in good faith to implement these principles in subsequent project implementation agreements.

ARTICLE 6: REGULATORY FRAMEWORK, ACCESS AND EXPANSION

6.1 The Parties have discussed a tailored regulatory framework for the Alaska LNG Project under Section 3 of the Natural Gas Act, 15 U.S.C. § 717b (“NGA Section 3”), and recognize the availability of this framework to meet the needs of all Parties.

6.2 During Pre-FEED, the Alaska LNG Project will be advanced under NGA Section 3.

6.3 Access and Pro-Expansion Principles.

- a. The Parties will advance development of a commercial structure that is consistent with the regulatory framework.
- b. AGDC and TADI shares of capacity in the Alaska LNG Project components would be owned and operated, in whole or in part, on terms that would provide access for third-parties, for both in-state and export volumes. These access terms would be developed by the State, AGDC and TADI and would utilize contract carriage principles.
- c. Each Producer Party’s individual capacity in the Alaska LNG Project components would be owned and operated on a proprietary basis.
- d. The Parties would jointly develop acceptable terms regarding firewalls and FERC adjudication, where appropriate.
- e. Expansion terms consistent with the “Pro-Expansion Principles” set forth in Appendix A would also be agreed by the Parties.

6.4 Prior to entering FEED, the following will be pursued in interactions with the FERC:

- a. The Parties will support, including holding discussions (as permitted by FERC rules) with the FERC staff regarding the application and implementation of NGA Section 3 to the Alaska LNG Project.
- b. Based on those discussions, the Parties will meet to consider the joint filing of a petition for declaratory order with FERC to confirm these principles.

Each Party must be satisfied with the commercial terms and regulatory framework prior to the execution of the FEED Agreement for the Alaska LNG Project.

6.5 To assist in addressing in-state gas demand, the Alaska LNG Project would include at least five in-state offtake points (“Offtake Point(s)”), with the specific locations determined by the Administration in consultation with AGDC. Any Party may deliver gas to an Offtake Point. Any facilities taking gas from an Offtake Point, including facilities associated with odorization, reduction of gas pressure, or control of gas heating value or gas quality, are not part of the Alaska LNG Project and would need to be funded, installed and maintained by third parties.

6.6 Third-party gas to be delivered into any component of the Alaska LNG Project must meet the gas quality specifications of the applicable Alaska LNG Project component, and must not adversely affect the cost of service, technical aspects or LNG quality from the Alaska LNG Project facilities.

ARTICLE 7: GENERAL ENABLING LEGISLATION

7.1 Alignment among parties is critical to the success of a project of the scope and magnitude necessary to develop Alaska gas resources. General legislation to allow State participation and gas share in any such project is critical for the progression and implementation of a project. Depending on the scope, size and other factors associated with a particular project, the level of State participation may vary. For projects that qualify under the general law, a mechanism to provide project-enabling terms would be needed.

7.2 To facilitate Alaska gas development and help advance the Alaska LNG Project and other qualifying projects, the Administration will submit proposed general legislation to the Alaska Legislature in the 2014 regular legislative session to:

- a. Establish terms for State participation and State gas share consistent with Articles 5, 8 and 9;
- b. Provide for a confidential process, subject to subsequent legislative ratification, to develop terms for project-enabling contracts; and
- c. Allow for inclusion of contract terms which could include and address: State participation; a State share of gas (royalty in kind and gas in lieu of production taxes); property taxes; upstream costs and lease expenditures; in-state gas deliveries; ownership interests; operating agreements; gas treatment, transportation, and liquefaction services agreements; State LNG or gas sales contracts; contract duration and durability; periodic project reporting; Alaska hire; Alaska contracting; and other terms necessary to advance projects to commercialize Alaska’s natural gas resources.

7.3 During the term of the HOA, and to the extent permitted by law, each Party agrees to include and support the provisions of Articles 5 through 12, inclusive, in any future legislation or contractual arrangements that could apply to the Alaska LNG Project.

7.4 Depending on the enactment of Enabling Legislation acceptable to the Parties, the Administration and the Alaska LNG Parties would use commercially reasonable efforts to negotiate project-enabling contracts consistent with that legislation and this HOA.

7.5 The Administration will submit to the Alaska Legislature, and the Parties will support, to the extent permitted by law, legislation in a 2015 legislative session to ratify any Alaska LNG Project-enabling contracts developed by the Parties under the process authorized in the 2014 legislation and address any other matters the Parties mutually agree are necessary for advancement of the Alaska LNG Project.

7.6 The Administration recognizes that projects proposed under the general law will have different needs, reflecting the complexity and magnitude of the investments required for the project, and that the corresponding duration of any such project contracts may vary.

ARTICLE 8: ROYALTIES AND PRODUCTION TAXES

8.1 Royalty.

8.1.1 Alaska law, as set forth in AS 38.05.182(a), provides that “royalties on oil and gas shall be taken in kind unless the commissioner determines that the taking in money would be in the best interest of the state.” Thus, absent a finding by the Commissioner of DNR that the taking of its royalty in money (commonly referred to as royalty in value, or “RIV”) for royalties generated as a result of the Alaska LNG Project would be in the best interest of the State, the royalties generated as a result of the Alaska LNG Project must be taken in kind (“RIK”).

8.1.2 The November 2013 “Alaska North Slope Royalty Study” performed by Black & Veatch (“Royalty Study”) at the direction of the Commissioner of DNR identifies several potential issues relating to the State taking RIK for an LNG export project including the State’s current lack of LNG marketing expertise.

8.1.3 Subject to the passage of Enabling Legislation and execution of project-enabling contracts including satisfactory arrangements for disposition of the State’s share of LNG:

8.1.3.1 The State will take as RIK the full royalty percentage permitted under the leases from which gas will be produced into the Alaska LNG Project for the Initial Project Term.

8.1.3.2 At least 36 months prior to the expiration of the Initial Project Term, the State will provide the Producer Parties advance written notice of any intention to elect to receive RIV, which election could only take effect after the Initial Project Term. If the State so elects to receive its royalty share in value at any time after the Initial Project Term, the relevant parties will need to agree on the terms for royalty valuation and corresponding impacts, if any, on the ownership in and capacity access to the Alaska LNG Project components.

8.1.3.3 The State and Producer Parties will modify any sliding scale royalty and net profits share royalty provisions in State leases from which gas will be

produced into the Alaska LNG Project to provide for a fixed percentage royalty and the State will take as RIK as provided in Section 8.1.3.1.

8.2 Gas Production Tax. With regard to gas production taxes, which, assuming Enabling Legislation is enacted, could be taken by the State either in cash or as gas (the latter being referred to herein as “Tax as Gas” or “TAG”), and subject to Section 8.1.3.1 and execution of project-enabling contracts including satisfactory arrangements for disposition of the State’s share of LNG:

- 8.2.1 For the Alaska LNG Project contemplated under this HOA, the State will provide each Producer Party with the right to exercise a one time, irrevocable election, with no sunset requirement, to make gross gas production tax payments that are equal to a fixed percentage of that Producer Party’s taxable gas. Each Producer Party’s fixed percentage gas payments will be made in lieu of the production tax payments due by that Producer Party on gas produced under Alaska law.
- 8.2.2 Upon an election by a Producer Party under Section 8.2.1, the State will receive a fixed percentage of that Producer Party’s gas at a fixed rate of its taxable gas, delivered to the State at each delivery point into a Transmission Line. The Parties anticipate that TAG would be approximately 7% to 13%.
- 8.2.3 The TAG would be structured to allow the gas volumes to remain bookable as reserves by the Producer Parties.

8.3 State Gas Share

- 8.3.1 All RIK gas and TAG provided by the Producer Parties and received by the State, (collectively “State Gas Share”), will be delivered with custody and title transferring to the State at the delivery point into a Transmission Line.
- 8.3.2 The State will be responsible for disposition of the State Gas Share beyond the delivery points, including the State share of LNG made from the State Gas Share.
- 8.3.3 Consistent with advice from antitrust counsel, the Producer Parties are willing, in conjunction with a fiscal arrangement for an Alaska LNG Project under which the State has a State Gas Share, to agree that each Producer Party, if asked by the State, would offer to negotiate separately with the State in good faith to enter into an agreement with the State regarding the purchase or other disposition of a portion of the LNG that is made from the State’s deliveries of natural gas to the Alaska LNG Project, with each Producer Party negotiating a potential agreement regarding the purchase or other disposition of a portion that equals or exceeds that Producer Party’s respective proportionate share of the total of the Producer Party’s capacities (i.e., exclusive of the capacity owned or used by the State) in the LNG Plant component of the Alaska LNG Project.

ARTICLE 9: OTHER PROJECT-ENABLING TERMS

9.1 Alignment of the Parties is critical to the success of an LNG export project of this scope and magnitude. Alaska LNG Project fiscal terms are based on the principle of a fair and transparent balance of risk and reward.

9.2 Project-enabling contracts negotiated between the Parties will need to be of sufficient duration to support investment decisions of the Alaska LNG Parties, to permit realization of a competitive economic return, to enable necessary financing, and to support gas and LNG sales agreements (“Initial Project Term”).

9.3 The Parties intend that the following fiscal terms, subject to them being commercially acceptable to all Parties, would be included in the project-enabling contracts for the Alaska LNG Project.

9.3.1 Subject to consultation by the Administration with local governments:

- a. Payments in lieu of property tax (“PILT”) would be paid by the Alaska LNG Parties on each component of the Alaska LNG Project. For the Alaska LNG Project, the PILTs would be on a unit rate per throughput basis (e.g., cents per thousand cubic feet, etc.) and could be level or escalating dollar payments for the Alaska LNG Project components.
- b. The Parties would establish a series of impact payments to be paid by the Alaska LNG Parties to help offset increased service and other costs borne by the State and local governments during construction of the Alaska LNG Project.

9.3.2 Other terms that the Parties may mutually agree are necessary to support a commercially viable qualified project, including provisions to make the contractual terms predictable and durable.

ARTICLE 10: ADDITIONAL STATE SUPPORT FOR THE ALASKA LNG PROJECT

10.1 The Administration acknowledges that State support for the Alaska LNG Project is needed in a number of areas to progress a successful Alaska LNG Project. These include, but are not limited to, support for:

- a. Use of eminent domain rights to facilitate implementation of the Alaska LNG Project design, permitting, financing, funding approval, construction and operation of the Alaska LNG Project, including drafting, introducing and supporting legislation where necessary;
- b. Any DOE export license application and any related DOE regulatory process for the Alaska LNG Project;

- c. Appropriations and permitting for the construction of necessary in-state infrastructure (e.g., roads, bridges), including drafting, introducing and supporting legislation;
- d. Other local, State and federal permitting requirements for the Alaska LNG Project;
- e. A healthy, long-term oil business; and
- f. Other areas, including drafting, introducing and enacting legislation in the 2015 legislative session to clarify State regulatory authority, if and to the extent required to effect the Alaska LNG Project regulation provided in Article 6 (e.g., amendment of the Alaska Right-of-Way Leasing Act to address common carrier pipeline and other requirements, if required).

ARTICLE 11: ALASKA HIRE AND CONTENT

- 11.1 For the Alaska LNG Project, the Alaska LNG Parties will, within the constraints of law:
- a. Employ Alaska residents and contract with Alaska businesses to the extent they are qualified, available, ready, willing, and cost competitive;
 - b. Use, as far as is practicable, job centers and associated services operated by the State Department of Labor and Workforce Development;
 - c. Participate with the State Department of Labor and Workforce Development to update the training plan for an LNG export project including marine operations;
 - d. Advertise for available positions locally and use, as far as practicable, Alaska job service organizations to notify the Alaska public; and
 - e. Work with the State Department of Labor and Workforce Development and other organizations to provide training.

11.2 Prior to construction, the Alaska LNG Parties commit to negotiate in good faith project labor agreements for the Alaska LNG Project.

ARTICLE 12: OTHER UNDERSTANDINGS

12.1 The Parties recognize that this HOA does not address all of the matters that must be dealt with or all of the terms and conditions needed to finalize project-enabling contracts among the Parties concerning a potential project. The Parties intend to work together and use commercially reasonable efforts to reach agreement on additional terms and conditions acceptable to all of the Parties.

12.2 In addition, the Parties will reasonably support cooperation between the Alaska LNG Project and the ASAP project on a technical and engineering basis so the State's options to connect the ANS gas resource to Alaskans are efficiently progressed.

ARTICLE 13: MISCELLANEOUS

13.1. Term and Termination

- a. This HOA will become effective as of the Effective Date.
- b. This HOA terminates December 31, 2015, unless extended by mutual agreement of the Parties.

13.2. Amendment and Modification

No amendment, modification, supplement or variation of this HOA will be effective unless in writing and signed by or on behalf of each Party.

13.3. Survival

The provisions of Articles 1 (Definitions) and 13 (Miscellaneous) will continue in full force and effect notwithstanding termination of this HOA.

13.4. No Liability or Damages

- 13.4.1. Nothing in this HOA requires any Party to reach or execute any legally binding or enforceable agreement(s) or to refrain from engaging in any business whatsoever, nor does any Party have any liability in connection with the subject matter of this HOA.
- 13.4.2. No Party is liable to any other Party or its Affiliates, officers, employees or agents, for any direct, indirect, special, incidental, consequential or punitive damages or otherwise liable for any loss of actual or potential profits, loss of production or business interruption arising out of or in any way connected with this HOA, including any breach of the terms of this HOA.

13.5. Governing Law

The laws of the State of Alaska, without giving effect to its conflicts of laws principles, will govern all questions concerning the construction, validity and interpretation of this HOA.

13.6. Transfer and Joinder

If an Alaska LNG Party, or its Affiliate, makes a Transfer during the term of this HOA, then the transferee ("Joining Party") may join as a Party to this HOA by executing a written instrument acceptable to the Parties. A Joining Party is considered both an Alaska LNG Party and a Party under this HOA.

13.7. Counterparts

This HOA may be executed in any number of counterparts and this has the same effect as if the signatures on the counterparts were on a single copy of the HOA.

IN WITNESS WHEREOF, the Parties caused this HOA to be executed by their duly authorized representatives on the date below their respective signatures but effective on the Effective Date.

State of Alaska Department of Natural Resources

By: [Signature]
Printed Name: Joe Balash
Title: Commissioner
Date: 1/14/14

State of Alaska Department of Revenue

By: [Signature]
Printed Name: Angela M Rodell
Title: Commissioner
Date: 1/14/2014

Alaska Gasline Development Corporation

By: [Signature]
Printed Name: DANIEL FAUSKO
Title: PRESIDENT
Date: 1-14-14

TransCanada Alaska Development Inc.

By: _____
Printed Name: _____
Title: _____
Date: _____

By: _____
Printed Name: _____
Title: _____
Date: _____

Heads of Agreement

January 14, 2014

IN WITNESS WHEREOF, the Parties caused this HOA to be executed by their duly authorized representatives on the date below their respective signatures but effective on the Effective Date.

State of Alaska Department of Natural Resources

By: _____

Printed Name: _____

Title: _____

Date: _____

State of Alaska Department of Revenue

By: _____

Printed Name: _____

Title: _____

Date: _____

Alaska Gasline Development Corporation

By: _____

Printed Name: _____

Title: _____

Date: _____

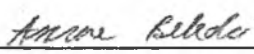
TransCanada Alaska Development Inc.

By: 

Printed Name: Tony Palmer

Title: President

Date: January 14, 2014

By: 

Printed Name: Annie C. Belecki

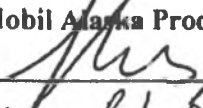
Title: Assistant Secretary

Date: January 14, 2014

Heads of Agreement

January 14, 2014

ExxonMobil Alaska Production Inc.

By: 
Printed Name: R.L. Briles *cy*
Title: President
Date: 1/13/2014

ConocoPhillips Alaska, Inc.

By: _____
Printed Name: _____
Title: _____
Date: _____

BP Exploration (Alaska) Inc.

By: _____
Printed Name: _____
Title: _____
Date: _____

Heads of Agreement

January 14, 2014

ExxonMobil Alaska Production Inc.

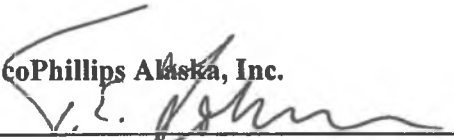
By: _____

Printed Name: _____

Title: _____

Date: _____

ConocoPhillips Alaska, Inc.

By:  _____

-B33 Printed Name: Trond-Erik Johansen

Title: PRESIDENT

Date: JANUARY 14, 2014

BP Exploration (Alaska) Inc.

By: _____

Printed Name: _____

Title: _____

Date: _____

B33 1/1

ExxonMobil Alaska Production Inc.

By: _____

Printed Name: _____

Title: _____

Date: _____

ConocoPhillips Alaska, Inc.

By: _____

Printed Name: _____

Title: _____

Date: _____

BP Exploration (Alaska) Inc.

By:  _____

Printed Name: Janet Weiss

Title: President

Date: January 14, 2014

Appendix A
Pro-Expansion Principles

The following principles are for the Alaska LNG Project regulated under NGA Section 3. These principles apply to any component of the Alaska LNG Project.

A.1 Alaska LNG Project Expansion. The potential expansion of any component of the Alaska LNG Project (excluding the modification of an installed Alaska LNG Project liquefaction train, or installation of a new liquefaction train) would be addressed in the agreements to be developed during Pre-FEED, reflecting the following principles.

- A.1.1 Following start-up of the Alaska LNG Project, any Alaska LNG Party may initiate the process for an expansion of any component of the Alaska LNG Project in which that Alaska LNG Party has an interest, unless that expansion would:
- a. Materially and adversely affect or alter the Alaska LNG Project facilities or operations, including technical aspects, or scheduling or quality of deliveries from the Alaska LNG Project facilities;
 - b. Diminish service to the existing shippers or users of the Alaska LNG Project;
 - c. Cause the Alaska LNG Project to be in violation of any applicable environmental or safety laws or regulation; or
 - d. Cause a violation of the Alaska LNG Project right-of-way agreements or any other contractual obligations with respect to the Alaska LNG Project facilities.

Subject to Section A.2 regarding modification of an existing LNG Plant liquefaction train and Section A.3 regarding installation of new LNG Plant liquefaction trains, if an Alaska LNG Project expansion is proposed, all Alaska LNG Parties with an interest in the Alaska LNG Project component being expanded will have the right, but not any obligation, to participate in the proposed expansion ("Expansion Party"). Any Expansion Party may request additional volumes thereby increasing the capacity of the proposed expansion. If, however, as a result of the review of the design and cost of the proposed expansion, all the Expansion Parties determine that they wish to reduce the size of the proposed expansion, then they may do so. An Alaska LNG Party's ownership interest in the post-expansion Alaska LNG Project component would be equivalent to the proportion of its capacity to the aggregate capacity on the post-expansion Alaska LNG Project component.

Expansions can proceed if they meet the criteria in Section A.1.1 above.

- A.1.2 The Expansion Parties will pay all costs related to the expansion and will have access to and share the incremental capacity developed by the expansion, provided terms related to impacts on fuel use for an expansion would be addressed during Pre-FEED by the Parties. Those Alaska LNG Parties that do not elect to participate

in the proposed expansion (“Non-Expansion Parties”), will be kept whole and will not bear any costs related to the expansion, will not have access to or share in the incremental capacity developed by the expansion, and will not bear any risks or adverse impacts of the expansion or that may result from the expansion, including construction, operation, commercial viability of the capacity expansion or level of capacity utilization.

- A.1.3 Both the Expansion Parties and the Non-Expansion Parties will share in the benefits of an expansion of an Alaska LNG Project component (other than access to or sharing of the expansion capacity). For example, if incremental capital costs of expansion on a unit of capacity basis are lower than the average pre-expansion capital costs per unit of capacity, the capital cost would be equalized, which could include some reallocation of past costs. In addition, both Expansion Parties and Non-Expansion Parties would share proportionately in any reduction in unit operating costs.

A.2 Modification of Installed Liquefaction Trains. The principle for any modification (e.g., debottlenecking) of the installed LNG Plant liquefaction trains is that any proposal for the modification would be subject to agreement of the Alaska LNG Parties with an interest in the LNG Plant liquefaction trains, as would be set forth in the LNG Plant operating agreement(s) among those Alaska LNG Parties.

A.3 New Liquefaction Train Installation Principles. The potential installation of a new liquefaction train would be addressed in the agreements to be developed during Pre-FEED, reflecting the following principles.

- A.3.1 Following start-up of the Alaska LNG Project, any Alaska LNG Party with an interest in the LNG Plant may initiate the process to install a new LNG Plant liquefaction train, unless that installation would:
- a. Materially and adversely affect or alter the Alaska LNG Project facilities or operations, including technical aspects, or scheduling or quality of deliveries from the Alaska LNG Project facilities;
 - b. Diminish service to the existing shippers or users of the Alaska LNG Project;
 - c. Cause the Alaska LNG Project to be in violation of any applicable environmental or safety laws or regulations; or
 - d. Cause a violation of the Alaska LNG Project right-of-way agreements or any other contractual obligations with respect to the Alaska LNG Project facilities.
- A.3.2 All Alaska LNG Parties with an interest in the LNG Plant will have the right, but not any obligation, to participate in a proposed liquefaction train installation at the LNG Plant location. Any Alaska LNG Party electing to participate in the new installation may request additional volumes, thereby increasing the capacity of the

proposed liquefaction train installation. If, however, as a result of the review of the design and cost of the new proposed installation, all of the Alaska LNG Parties that have elected to participate in the new liquefaction train installation determine that they wish to reduce the size of the new proposed installation, then they may do so. Each Alaska LNG Party that participates in a new proposed liquefaction train installation would have an ownership interest in that new liquefaction train equivalent to its equity interest in that new liquefaction train.

Installation of a new liquefaction train can proceed if it meets the criteria in Section A.3.1. above.

A.3.3 Any use, including expansion, of existing LNG Plant property, utilities, storage and marine terminal in conjunction with a new liquefaction train installation will be subject to the expansion principles set forth in Section A.1 above.

A.4 Alaska LNG Project Gas Quality. Notwithstanding anything to the contrary, all gas entering any component of the Alaska LNG Project must meet the gas quality specification applicable to that Alaska LNG Project component.

EXHIBIT I

Exhibit I-A
CEO Letter

CEO Letter to Governor Parnell dated March 30, 2012

ExxonMobil

ConocoPhillips



March 30, 2012

Governor Sean Parnell
550 West 7th Avenue, Suite 1700
Anchorage, Alaska 99501

Dear Governor Parnell,

Our three corporations, collectively and individually, value our relationship with Alaska and believe that its citizens across the state, as well as our shareholders around the world, share a common interest in responsible resource development. We write today to inform you of our progress in working together on the next generation of North Slope resource development.

Alaska's vast North Slope holds over 35 trillion cubic feet of discovered natural gas. To date, this gas has been used to enhance North Slope oil production, adding several billion barrels to Prudhoe and Kuparuk recoveries. However, under the right business climate, the full commercial potential of this world-class resource can be unlocked. North Slope gas commercialization will bring new job opportunities, increased state revenues, reliable in-state energy supplies and new exploration opportunities, which will further the development of North Slope oil and gas. This will be key toward reaching your goal of one million barrels of oil per day through the Trans-Alaska Pipeline System.

Serious discussions between our companies have taken place over the past several months, along with the Alaska Pipeline Project (APP) parties who are supporting the AGIA License. We have aligned on a structured, stewardable and transparent approach with the aim to commercialize North Slope natural gas resources within an AGIA framework. As a result of the rapidly evolving global market, large-scale liquefied natural gas (LNG) exports from south-central Alaska will be assessed as an alternative to gas line exports through Alberta. In addition to broadening market access, a south-central Alaska LNG approach could more closely align with in-state energy demand and needs. We are now working together on the gas commercialization project concept selection, which would include an associated timeline and an assessment of major project components including in-state pipeline routes and capacities, global LNG trends, and LNG tidewater site locations, among others.

Commercializing Alaska natural gas resources will not be easy. There are many challenges and issues that must be resolved, and we cannot do it alone. Unprecedented commitments of capital for gas development will require competitive and stable fiscal terms with the State of Alaska first be established. Appropriately structured, stable fiscal arrangements have opened new opportunities around the world, and will play a pivotal role in making Alaska competitive in the global market and unlocking the economic potential of North Slope resources.

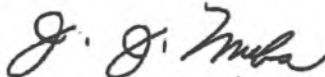
Point Thomson is an excellent example of a challenged, world-class resource. With approximately 25% of known North Slope natural gas, Point Thomson development is an important element in consideration of North Slope gas commercialization. However, economic models must span decades into an uncertain future to estimate economic returns. Your Administration has taken the lead in forging a Point Thomson settlement that will bring long-term resources, revenues and jobs to help Alaska's economy. With settlement now finalized, our companies are moving forward, as participating co-venturers, with the initial development phase at Point Thomson with confidence that North Slope gas development will ultimately bring the Point Thomson resource to market.

We agree the next generation of North Slope resource development is achievable, working together with the APP parties, as well as with the State of Alaska. Thank you for your leadership and your confidence in us to take on these challenges. We join you in a vision of prosperity and promise. There is much work to do and opportunities yet to discover.

Sincerely,



Rex Tillerson



Jim Mulva



Bob Dudley

Exhibit I-B
Alaska LNG Project Update Letter

Alaska LNG Project Sponsor Letter to Governor Parnell dated October 1, 2012

- Project Update



October 1, 2012

Governor Sean Parnell
550 West 7th Avenue, Suite 1790
Anchorage, Alaska 99501

Dear Governor Parnell:

On March 30, 2012, ExxonMobil, ConocoPhillips and BP submitted a letter informing you of progress in working together on the next generation of North Slope resource development. Since that time, the three producer companies and TransCanada, through its participation in the Alaska Pipeline Project (APP), have maintained momentum and executed important early work to select leading concepts for a potential project. We are writing to update you on the progress that has been made to date.

We established an integrated team, depicted on Attachment 1, committing significant resources and the efforts of over 200 professionals to date to progress this work. This allowed us to combine our respective talents and experience to advance a collective understanding of what would be required for liquefied natural gas (LNG) exports from Southcentral Alaska. Our team has advanced extensive work to refine and understand the opportunities and challenges associated with North Slope natural gas development.

Our companies bring together specific expertise in Arctic operations, pipeline design and construction, and in LNG plant design and operation. Since our joint work began at the end of March, we have built upon more than \$700 million in past work by our collective companies, including the joint Alaska Gas Producer Pipeline Team effort in 2001-02, the Denali Project, and APP (including the State's contribution through AGIA). As a result, our work on an LNG development project has been advanced to a new level of understanding. Specifically, the focus of our work includes:

- Developing a design basis for the pipeline, including areas of continuous and discontinuous permafrost
- Investigating multiple ways to remove and dispose of CO₂ and other contaminants
- Assessing use of existing and addition of new Prudhoe Bay field facilities
- Mapping multiple pipeline routing variations
- Assessing multiple pipeline sizes
- Providing for at least five in-state gas off-take points
- Completing preliminary geohazard and marine analysis of 22 LNG site locations
- Developing a design basis for the required LNG tanker fleet
- Evaluating multiple LNG process design alternatives
- Confirming a range of gas blends from the Prudhoe Bay and Point Thomson fields can generate a marketable LNG product

We have narrowed the broad range of alternative development concepts and assessed major project components, including the gas pipeline, gas treatment to remove CO₂ and other impurities, natural gas liquefaction, LNG storage, and marine terminal facilities as described on Attachment 2. Individually,

each of these components would represent a world-class project. Combined, they result in a mega-project of unprecedented scale and challenge; up to 1.7 million tons of steel, a peak construction workforce of up to 15,000, a permanent workforce of over 1,000 in Alaska, and an estimated total cost in today's dollars of \$45 to \$65+ billion.

Additional accomplishments include TransCanada's recently completed non-binding solicitation of interest in accordance with AGIA. TransCanada has publicly reported interest from potential shippers and major players from a broad range of industry sectors and geographic locations. Additionally, TransCanada, on behalf of the APP parties, has advised that a cooperative framework has also been established with the Alaska Gasline Development Corporation for information exchange.

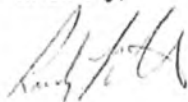
We are encouraged by the synergies and efficiencies identified by our integrated team. While good progress has been made, significant environmental, regulatory, engineering and commercial work remains to reach upcoming decisions to bring North Slope gas to market. A diagram indicating work plans and key decision points is provided on Attachment 3. This attachment describes ranges and durations for engineering and technical work. However, these durations could be extended by external factors including resolution of fiscal terms, regulatory and permitting delays, and legal challenges, among others. As the concept selection technical work reaches closure, additional commercial agreements as well as support from the State of Alaska will be required in order to progress this world-class opportunity.

This opportunity is challenged by its cost, scale, long project lead times, and reliance upon interdependent oil and gas operations with declining production. The facilities currently used for producing oil need to be available over the long-term for producing the associated gas for an LNG project. For these reasons, a healthy, long-term oil business, underpinned by a competitive fiscal framework and LNG project fiscal terms that also address AGIA issues, is required to monetize North Slope natural gas resources. The producers look forward to working with the State to secure fiscal terms necessary to support the unprecedented commitments required for a project of this scope and magnitude and bring the benefits of North Slope gas development to Alaska.

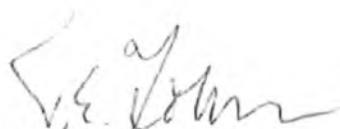
Our next steps are to complete the concept selection phase and work with the State to make meaningful progress on the items detailed above. This work is critical as we consider decisions to progress the next phases of an LNG development project.

Alaska's North Slope natural gas resources must compete in the global energy markets in order to deliver state revenues, in-state energy supplies, new job opportunities and other economic benefits to Alaskans. While North Slope gas commercialization is challenging, working together, we can maintain the momentum toward our shared vision for Alaska. We will continue to keep you advised of our progress and stand committed to work with the State to responsibly develop its considerable resources.

Sincerely,



Randy Broiles
ExxonMobil
Production Company



Trond-Erik Johansen
ConocoPhillips Alaska, Inc.



John Mingé
BP Exploration Alaska

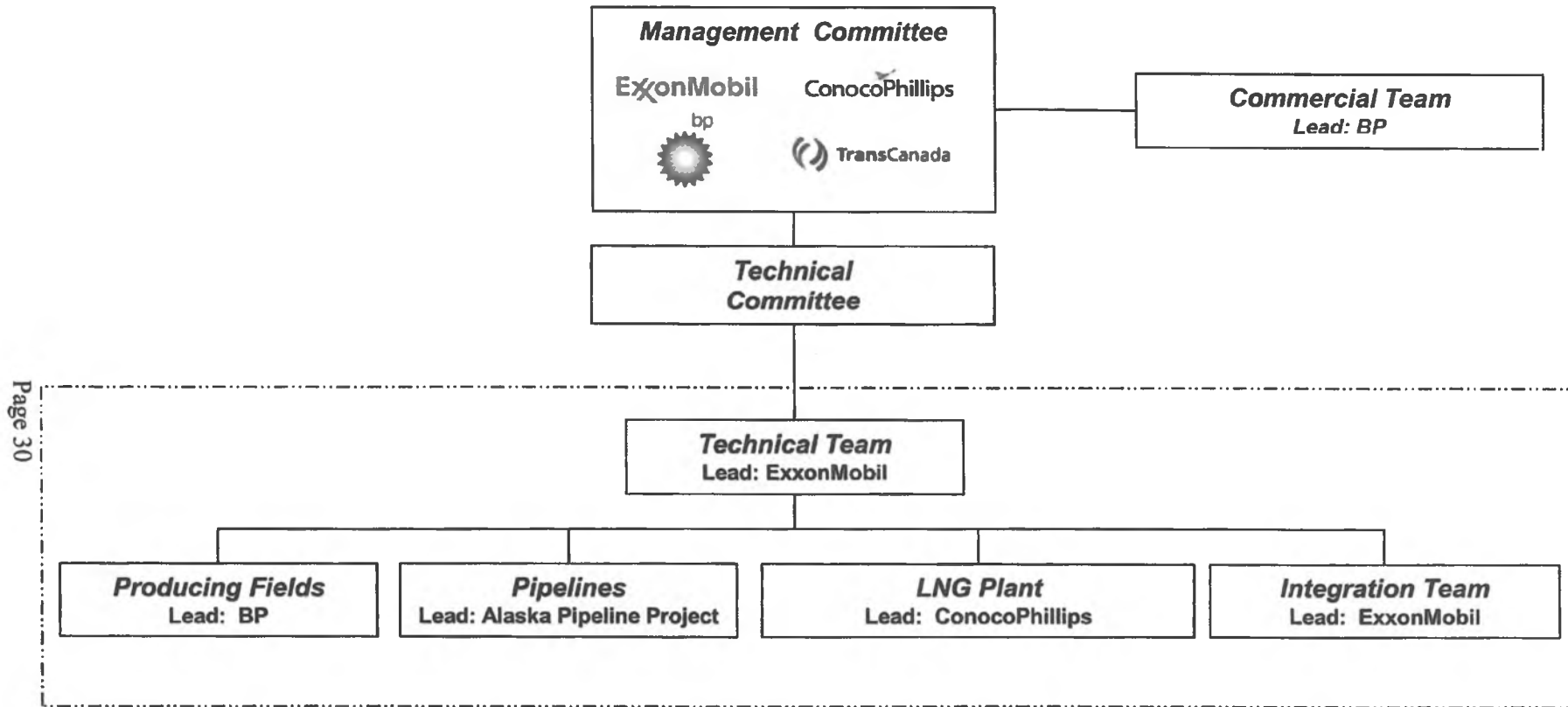


Tony Palmer
TransCanada

Attachments

Attachment 1

Southcentral Alaska LNG – Integrated Team



Multimillion Dollar, Four-Company Effort – 125+ Employees, 100+ Contractors

- Joint work commenced March 31, 2012 after completion of the Pt. Thomson Settlement / joint work agreements
- Cooperative effort among the leading North Slope producers and a leading North American pipeline company
- Identified potentially viable LNG project options to monetize ANS natural gas
- Used company strengths, shared information / expertise; built upon past efforts, sought out new ideas

Attachment 2

Alaska Southcentral LNG – Project Concept Description

Liquefaction Plant

- Capacity: 15 – 18 million tonnes per annum (MTA)
3 trains (5-6 MTA / train)
- Potential areas: 22 sites assessed in Cook Inlet, Prince William Sound and other Southcentral sites
- Footprint: 400 - 500 acres
- Peak Workforce: 3,500 - 5,000 people
- Required Steel: 100,000-150,000 tons



Producing Fields

- ~35 TCF discovered North Slope resource
- Additional exploration potential
- Anchored by Prudhoe Bay and Pt. Thomson with ~20 years supply available
- Use of existing and new North Slope facilities
- Confirmed range of gas blends from PBU/PTU can generate marketable LNG product
- Peak Workforce: 500 – 1,500 people



Storage / Loading

- LNG Storage Tanks, Terminal
- Dock; 1 - 2 Jetties
- Design based on 15– 20 tankers
- Peak Workforce: 1,000-1,500 people

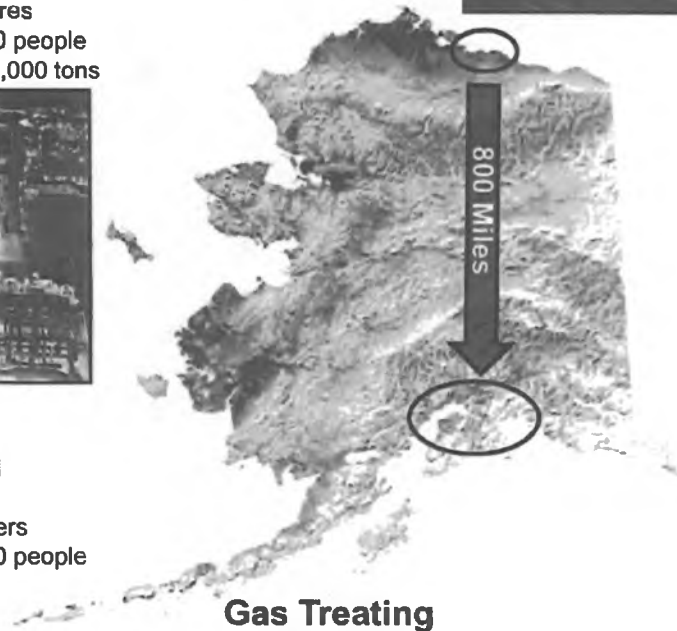


Gas Treating

- Located at North Slope or Southcentral LNG site
- Remove CO₂ and other gases and dispose / use
- Footprint: 150 - 250 acres
- Peak Workforce: 500 - 2,000 people
- Required Steel: 250,000 - 300,000 tons
- Among largest in world

Pipeline

- Large diameter: 42"- 48" operating at >2,000 psi
- Capacity: 3 - 3.5 billion cubic feet per day
- Length: ~800 miles (similar to TAPS)
- Peak Workforce: 3,500 - 5,000 people
- Required Steel: 600,000 - 1,200,000 tons
- State off-take: ~5 points, 300-350 million cubic feet per day, based on demand



Estimated Total Cost: \$45 – \$65+ Billion

Peak Construction Workforce: 9,000 – 15,000 jobs

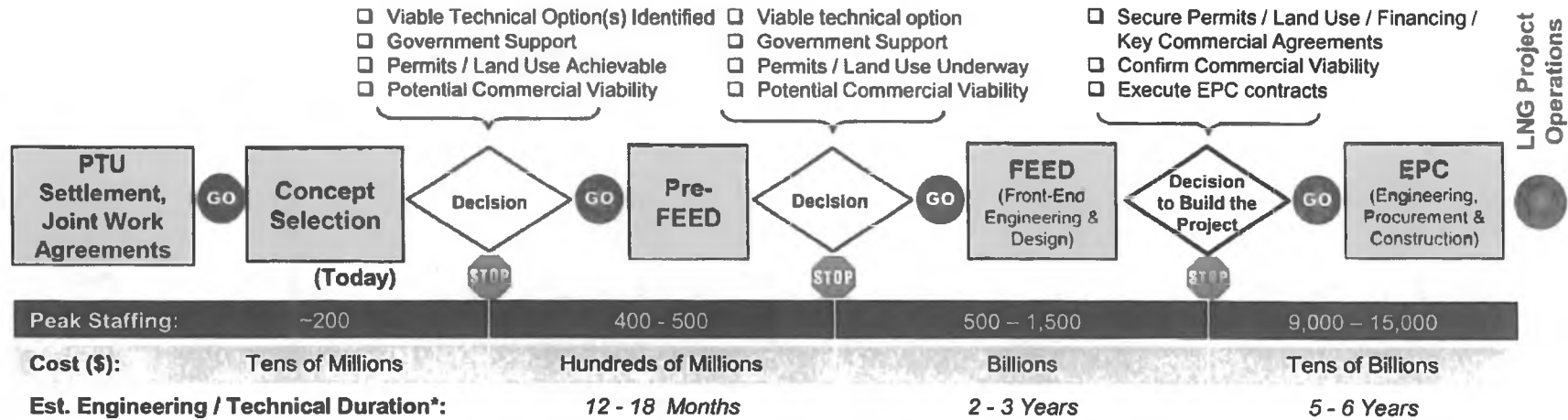
Operations Workforce: ~1000 jobs in Alaska

Descriptions and costs are preliminary in nature and subject to change. Cost range excludes inflation.

Attachment 3

Southcentral Alaska LNG – Work Plans / Key Decision Points

Requirements to Take Next Step:



Activities

Evaluate:	Progress:	Complete:	Execute:
<ul style="list-style-type: none"> • Range of technically viable options for major project components • Business Structure • In-state gas / export LNG demand 	<ul style="list-style-type: none"> • Preliminary engineering to refine concept • Business structure • Financing plan 	<ul style="list-style-type: none"> • Front-end engineering & design • Major contract preparation • Business structure • Financing arrangements 	<ul style="list-style-type: none"> • Final engineering • Financing • Procurement • Fabricate / Logistics / Construct • Prepare for Operations
Solicit Interest of Others		Solicit Interest of Others	
Establish Government Support and Advance Regulatory Issues: <ul style="list-style-type: none"> • Competitive oil tax environment; predictable / durable LNG project fiscal terms; AGIA Issues • Assure ability to secure regulatory approvals / permits / land use • Environmental activities / Technical data collection • Stakeholder engagement • File DOE Export License 		Advance Gov't / Reg. Issues: <ul style="list-style-type: none"> • Key permit / land use approvals • Stakeholder engagement • Secure DOE Export License 	
	Start individual gas / LNG sales / shipping efforts	Execute individual gas / LNG sales / shipping agreements	Implement business structure & agreements
Screen commercial viability	Assess commercial viability	Confirm commercial viability	Commission / start-up

* NOTE: Duration of various phases may be extended by protracted resolution of fiscal terms, permitting and regulatory delays, legal challenges, changes in commodity market outlook, time to secure long-term LNG contracts, labor shortages, material & equipment availability, weather, etc.

Exhibit I-C
Alaska LNG Project Concept Selection Letter

Alaska LNG Sponsor Letter to Governor Parnell dated February 15, 2013

- Concept Selection



February 15, 2013

Governor Sean Parnell
550 West 7th Avenue, Suite 1790
Anchorage, Alaska 99501

Dear Governor Parnell,

On October 1, 2012 we updated you on the progress ExxonMobil, ConocoPhillips, BP and TransCanada had made to advance North Slope natural gas development. At that time, we described our plans for progressing concept selection. Today, we are pleased to inform you we have completed the concept selection phase.

Attached is a summary of the major project components, including the gas pipeline, gas treatment facilities and the liquefaction, storage and terminal facilities. The project design also includes five off-take points along the pipeline route to ensure Alaskans access to a cleaner-burning and dependable energy source. Capacity ranges reflect the expected seasonal variability. The conceptual design reflects the integrated teamwork of over 300 people on behalf of our companies.

Our companies are now working toward the next decision points. As outlined in our letter of October 1, 2012, a competitive, predictable and durable oil and gas fiscal environment will be required for a project of this unprecedented scale, complexity and cost, to compete in global energy markets.

A successful Alaska LNG project would result in thousands of jobs and the opportunity for decades of domestically-produced natural gas for homes and businesses in Alaska. We remain committed to responsibly developing the State's considerable resources and will keep you advised of our progress. We also have plans to update the Legislature at a Lunch and Learn on February 19.

Sincerely,

Randy Broiles
ExxonMobil Production
Company

Trond-Erik Johansen
ConocoPhillips Alaska, Inc.

Janet Weiss
BP Exploration Alaska

Tony Palmer
TransCanada

Attachment

Proposed Alaska LNG Project Concept

Pipeline	Diameter: 42"
	Design Rate¹: 3 – 3.5 billion cubic feet
	Length: ~800 miles (primarily underground)
	Compressor Stations: up to 8
Gas Treatment Plant	Location: North Slope, near Prudhoe Bay
	Footprint: 150 – 250 acres
Liquefaction Plant	Capacity¹: 15 – 18 million tons per annum (MTA)
	Facility: 3 trains
	Footprint: 400 – 600 acres
Storage and Loading	LNG Storage Tanks: 2 tanks @ 160,000 cubic meters per tank
	Terminal: 1 loading jetty with 2 berths
State Off-takes	Off-takes: 5 points along pipeline route
	Design Rate: 250 – 500 million standard cubic feet per day, based on demand
Capital Investment	Estimate²: \$45 – \$65 USD-Billion

¹ Capacity range reflects seasonal variability

² Does not include inflation

MEMORANDUM OF UNDERSTANDING

THIS MEMORANDUM OF UNDERSTANDING (the "MOU") is made effective and entered into this 12th day of December, 2013 (the "Effective Date"), by **TRANSCANADA ALASKA COMPANY, LLC** ("TC Alaska"), a Delaware limited liability company, **FOOTHILLS PIPE LINES LTD.** ("Foothills" and together with TC Alaska, the "Licensee"), a Canadian corporation, in their capacity as the Licensee under AGIA, **TRANSCANADA ALASKA DEVELOPMENT INC.** ("TADI"), a Delaware corporation, and **THE STATE OF ALASKA** (the "State") acting through the Alaska Commissioner of Natural Resources and the Alaska Commissioner of Revenue ("Commissioners") pursuant to their authority under Alaska Gasline Inducement Act ("AGIA"), AS 43.90.010 *et seq.*;

Recitals

1. The Alaska Legislature enacted AGIA in 2007 to encourage expedited construction of a natural gas pipeline that facilitates commercialization of North Slope oil and gas resources in the state to promote exploration and development of North Slope oil and gas resources in the state, to maximize benefits to the people of the state from the development of oil and gas resources in the state, and to encourage oil and gas lessees and other persons to commit to ship natural gas from the North Slope to a gas pipeline system for transportation to markets in this state or elsewhere.
2. On December 5, 2008, the Commissioners issued the AGIA license to Licensees. The Licensees, and subsequently with an affiliate of ExxonMobil, commenced to jointly develop the AGIA pipeline project in Alaska and Alberta as the Alaska Pipeline Project ("APP"). Over the following three years, the Licensee pursued the APP in compliance with AGIA requirements to timely conduct an initial binding open season and engage in the pre-filing process to prepare its project application to Federal Energy Regulatory Commission ("FERC") for a certificate of public convenience and necessity.
3. In October 2011, in response to changed circumstances in world gas markets, including a substantial increase in U.S. shale gas reserves and lower natural gas prices in the U.S., significantly higher natural gas prices in Asia and other world markets, and the projection that the U.S. will become a net exporter of natural gas, Governor Parnell requested the Licensee to work cooperatively with the Alaska North Slope oil producers (ExxonMobil, BP and ConocoPhillips, jointly "ANS Producers") to evaluate the economic feasibility of a liquefied natural gas ("LNG") alternative.
4. In response to the Governor's request, the Licensees requested a project plan amendment ("PPA") to the AGIA license to facilitate participation by the APP with the ANS Producers in a concept selection assessment of an LNG alternative specifically relating to gas pipeline facilities to deliver natural gas from the Alaska North Slope to the tidewater of south-central Alaska for in-state use and export. The Commissioners approved the Licensee's PPA authorizing the Licensee to participate in a concept selection process for the Alaska LNG Project with the ANS Producers. The Commissioners approved additional PPAs to facilitate the Licensee's continued participation with the ANS Producers in completion of the concept selection phase for the Alaska LNG Project.
5. The Licensee, through its affiliate, TADI, and the ANS Producers have selected a concept for the Alaska LNG Project and are preparing for the pre-FEED phase of the Alaska LNG Project.
6. The Commissioners have determined that in order to facilitate the financing and expedite the development and construction of the Alaska LNG Project it is desirable for the State to participate with the Licensee and the ANS Producers in the Alaska LNG Project. State participation in the Alaska

LNG Project is expected to yield significant benefits, including the alignment of interests, greater transparency for the State on the commercial terms of the project, and the reduction of disputes. As part of its participation in the Alaska LNG Project, the State would enter into certain commercial agreements with the Licensee, TADI and the ANS Producers, subject to legislative authorization for this purpose.

7. The Commissioners have determined that the State will benefit by entering into commercial arrangements with TADI for participation in the Alaska LNG Project. The Licensee's TADI's and its Affiliates' extensive pipeline experience and knowledge of northern pipeline conditions is an asset to the State's participation. The information gained and the assets developed by the Licensee and its Affiliates in developing the APP project under AGIA will significantly contribute to the development and construction of the Alaska LNG Project, and promote the State's objectives of facilitating construction of a natural gas pipeline that promotes exploration and development of oil and gas resources on the North Slope and maximizes benefits to the people of the State from the development of oil and gas resources.

8. The Commissioners have determined that it is in the State's interest to continue its relationship with the Licensee and its Affiliates as an experienced pipeline developer and to transition from the AGIA license to a commercial relationship between the State and TADI through TADI (an Affiliate of the Licensee) in relation to the Alaska LNG Project. To maintain project momentum and promote continued cooperation between the AGIA Licensee and the ANS Producers, the Commissioners, exercising their authority under AS 43.90.210, have approved the Licensee's request for PPA-1B for the Licensee's continued participation with the ANS Producers in preparation for the pre-FEED phase of the Alaska LNG Project and to prepare for the transition mentioned above. (Exhibit "A")

9. The Commissioners have engaged in discussions with the Licensee, TADI and the ANS Producers to determine commercial arrangements that would be feasible and desirable for the State to participate in the Alaska LNG Project. The Commissioners, TADI and the Licensee have determined that certain commercial arrangements are necessary in order for the State to participate with TADI to facilitate the Alaska LNG Project. The terms of those commercial arrangements are provided in the term sheets at Exhibit B and Exhibit C to this MOU. The Commissioners, TADI and the Licensee acknowledge that the terms provided in Exhibits B and C have no force or effect until the effective date of the Enabling Legislation (defined below) that authorizes the State to negotiate and execute the commercial agreements that are set out in the terms of the Exhibits to this MOU. The terms of commercial agreements that the State has discussed with ANS Producers to facilitate the State's participation in the Alaska LNG Project, are provided in separate documents and are not part of this MOU.

10. The Commissioners, TADI, and the Licensee agree that execution of the Transition Agreements (as defined below) will complete the transition of the relationship between the State, TADI, and the Licensee from AGIA to a commercial arrangement. Subject to Enabling Legislation, upon execution of the Transition Agreements, and finalization of commercial relations with ANS Producers for the Alaska LNG Project:

- a. TADI or its Affiliate would hold an ownership interest in the midstream portion of the Alaska LNG Project;
- b. The State would hold an option to acquire an equity interest in the TADI or the TADI Affiliate that will hold TADI's ownership interest in the Alaska LNG Project as identified in the Term Sheet at Exhibit B; and
- c. TADI or its Affiliate would provide gas processing and transportation services on the Alaska LNG Project for the State's share of gas as identified in the Term Sheet at Exhibit C.

11. The Commissioners have committed that after Enabling Legislation becomes effective and execution of the commercial agreements committing the ANS Producers to initiate the pre-FEED phase of the Alaska LNG Project, the Commissioners will initiate the process of making a determination for purposes of AS 43.90.240(a). Because it is not economically feasible that two large-scale pipeline projects will be developed concurrently to transport Alaska North Slope natural gas to market, the Commissioners have committed to consider the commercial agreements executed by and between the State, TADI and the ANS Producers for development of the Alaska LNG Project as material evidence that the Licensee's AGIA licensed project is uneconomic as provided in AS 43.90.240(a).

12. The Licensee has committed that upon the occurrence of the Trigger Event and the execution of the Transition Agreements, the Licensee will agree that the project licensed under the AGIA License is uneconomic within the meaning of AS 43.90.240(a).

13. The purpose of this MOU is to set out the Parties' agreement regarding the negotiation and execution of the Transition Agreements upon the occurrence of the Trigger Event, specifically –

- a. the Alaska LNG Project Equity Option Agreement; and
- b. the Alaska LNG Midstream Services Agreement.

NOW THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter set forth, each Party to this MOU hereby agrees as set forth below.

ARTICLE 1 DEFINED TERMS

1.1 Defined Terms

The following definitions shall, for all purposes, unless otherwise clearly indicated to the contrary, apply to the capitalized terms used herein:

- (a) **"Affiliate"** means in relation to a Party any company, corporation, partnership or other legal entity (in this definition, each such entity and each Party are sometimes referred to as a "Company") which is:
 - (i) directly or indirectly, owned or controlled by such Party;
 - (ii) directly or indirectly owns or controls such Party; or
 - (iii) directly or indirectly, owned or controlled by a Company that also, directly or indirectly, controls such Party.

For the purpose of this definition, a Company is directly owned or controlled by another Company that owns or controls shares or other interests carrying in the aggregate more than 50 percent of the voting rights exercisable at a general, shareholders, or members meeting of the first-mentioned Company, or the right to appoint or dismiss a majority of the directors thereof, or the power to direct or cause the direction of the management or policies through the ownership of securities, by contract or otherwise. A Company is indirectly owned or controlled by a Company or Companies (the "parent Company or Companies") if a series of Companies can be specified, beginning with the parent Company or Companies and ending with the particular Company, so related that each Company of the series, except the parent Company or Companies, is directly controlled by one or more of the Companies in the series.

For the purpose of this definition, the definition of a State Affiliate includes the State of Alaska acting in its proprietary capacity, any State authority or independent public corporation of the State (“IPC”), any subsidiary corporations created by an IPC (“SIPC”), and the State governmental entity members of any such IPC and SIPC.

- (b) **“AGIA”** means the Alaska Gasline Inducement Act, AS 43.90, as well as the regulations promulgated thereunder.
- (c) **“AGIA License”** means the license dated December 5, 2008, as amended by project plan amendments approved on January 29, 2010, May 2, 2012, June 11, 2013 and December 12, 2013.
- (d) **“AGIA Project Plan Amendment1B”** means the project plan amendment under the AGIA License approved by the Commissioners pursuant to AS 43.90.210 on December 12, 2013, (attached hereto as Exhibit “A”).
- (e) **“Alaska LNG Midstream Services Agreement”** means a Precedent Agreement (or similar agreement), and a Firm Transportation Services Agreement entered into between TADI and the State containing the terms set out in Exhibit “C”.
- (f) **“Alaska LNG Project”** means collectively, the PBU Gas Transmission Line, the PTU Gas Transmission Line, the Gas Pipeline, the Gas Treatment Plant, the LNG Plant, and the Marine Terminal. For the purposes of this definition:
 - (i) **“PBU Gas Transmission Line”** means a natural gas transmission line from the outlet flange of the Prudhoe Bay Unit Central Gas Facility to the inlet flange of the GTP;
 - (ii) **“PTU Gas Transmission Line”** means a natural gas transmission line from the outlet flange of the Point Thomson Unit production facility to the inlet flange of the GTP;
 - (iii) **“Gas Treatment Plant”** or **“GTP”** means those facilities and related activities required to receive natural gas from the PBU Gas Transmission Line, the PTU Gas Transmission Line, and/or other facilities, treat the natural gas to pipeline specifications, dispose of or deliver by-products, deliver liquid products for further transportation, and deliver treated natural gas for transportation through the Gas Pipeline;
 - (iv) **“Gas Pipeline”** means the main natural gas pipeline from the outlet flange of the GTP on the Alaska North Slope to the inlet flange of the LNG Plant located in South Central Alaska, which may have off-take points along the pipeline for deliveries of gas within the State of Alaska (Gas Pipeline refers to the main gas pipeline and does not include any gas lines downstream of any off-take point between the GTP and the LNG Plant);
 - (v) **“LNG Plant”** means the facility, including the structures, equipment, underlying land rights and all other associated systems, for pre-processing and liquefaction of natural gas, and storage, and off-loading of liquefied natural gas; and **“Marine Terminal”** means the terminal and those facilities required to receive LNG from the boundary of the LNG Plant for marine transportation, including auxiliary vessels used in the operation of the terminal.
- (g) **“Alaska LNG Project Equity Option Agreement”** means an agreement to be entered into between TADI and the State containing the terms set out in Exhibit “B”.

- (h) **“ANS Producers”** has the meaning given in paragraph 3 of the recitals.
- (i) **“CSA”** means the Concept Selection Agreement for ANS Gas Development dated March 29, 2012 between TADI and the ANS Producers, as amended from time to time.
- (j) **“Commissioners”** has the meaning given in the preamble of this MOU.
- (k) **“Effective Date”** has the meaning given in the preamble to this MOU.
- (l) **“Enabling Legislation”** means legislation enacted by the Alaska Legislature that has become effective as provided under AS 01.10.070 , and that at a minimum:
 - (i) Authorizes the Commissioners to negotiate and enter into the Transition Agreements, and
 - (ii) Authorizes the Commissioners to negotiate and enter into commercial arrangements with the ANS Producers for the Alaska LNG Project;
 - (iii) Funds the State’s contingent and direct payment obligations for development costs under the Precedent Agreement and Article 4.2 of this MOU.
- (m) **“HOA”** means the Heads of Agreement to be executed between the State, TADI, the ANS Producers and Alaska Gasline Development Corporation.
- (n) **“MOU”** means this memorandum of understanding and the attachments hereto.
- (o) **“Operative Terms”** means the terms to be incorporated in the Transition Agreements set out in Exhibits “B” and “C”, as same may be modified as a result of the application of Article 2.1(e).
- (p) **“Parties”** means TransCanada Alaska Company, LLC., Foothills Pipe Lines Ltd., TransCanada Alaska Development Inc., and the State of Alaska.
- (q) **“Pre-FEED JVA”** means the Alaska LNG Project Pre-FEED Venture Agreement to be executed, after Enabling Legislation becomes effective, by the ANS Producers, TADI and Alaska Gasline Development Corporation on terms acceptable to the parties, as may be amended from time to time.
- (r) **“Precedent Agreement”** means the precedent agreement referred to in Alaska LNG Midstream Services Agreement Term Sheet attached hereto as Exhibit “C”.
- (s) **“Transition Agreements”** mean the Alaska LNG Project Equity Option Agreement and the Alaska LNG Midstream Services Agreement.
- (t) **“Trigger Event”** means the effective date of Enabling Legislation that the Licensee, TADI and the State determine to be acceptable. For purposes of determining whether the Enabling Legislation is acceptable, the Parties will evaluate whether the Enabling Legislation provides appropriate and sufficient authority to the State;
 - (i) to negotiate and execute the Precedent Agreement and the Alaska LNG Project Equity Option Agreement;
 - (ii) to negotiate the Firm Transportation Services Agreement; and

- (iii) to fund the State's contingent and direct payment obligations for development costs under the Precedent Agreement and Article 4.2 of this MOU.

1.2 Exhibits

The following exhibits are attached to and form part of this MOU:

Exhibit "A"	AGIA Project Plan Amendment #1B
Exhibit "B"	Alaska LNG Project Equity Option Agreement Term Sheet
Exhibit "C"	Alaska LNG Midstream Services Agreement Term Sheet

ARTICLE 2 TRANSITION AGREEMENTS

2.1 Negotiation of Transition Agreements

(a) The Parties and the ANS Producers have agreed that it is necessary and a condition subsequent for this MOU for the Legislature to enact Enabling Legislation. The State undertakes to seek Enabling Legislation.

(b) The Parties agree that they shall promptly proceed in good faith to negotiate the Transition Agreements, to be finalized and executed after the Trigger Event.

(c) The Parties acknowledge that the Operative Terms (as defined in Exhibits "B" and "C") set forth the understanding of the Parties as to the commercial principles set forth therein and, subject to Articles 2.1 (d) and (e) below, shall form the basis for negotiation of the Transition Agreements. The Parties acknowledge that the Operative Terms set forth in Exhibits "B" and "C" have been agreed by the Parties and that subject to Articles 2.1 (d) and (e) below, the provisions of the Transition Agreements shall be consistent with the commercial principles set out in the Operative Terms. Subject to Articles 2.1 (d) and (e) below, no Party shall negotiate any term in the Transition Agreements inconsistent with the Operative Terms. However, the Parties acknowledge and agree that Exhibits "B" and "C" do not contain all of the terms and conditions that would be included in the legally binding Transition Agreements between the Parties.

(d) The Parties agree to support the approval of the Operative Terms in the Enabling Legislation, but acknowledge that the Enabling Legislation may include authorizations or conditions that vary from or conflict with the Operative Terms. In such event, and if Parties agree to accept the Enabling Legislation, then the Transition Agreements will reflect the Enabling Legislation terms and conditions notwithstanding the Parties' acknowledgement in Article 2.1(c) above.

(e) The Parties acknowledge that insofar as the terms of the Heads of Agreement ("HOA"), the Pre-Feed JVA, or any future Alaska LNG agreement to which the SOA or an entity of the SOA (including AGDC) is a party or which the State has approved are at variance with the Operative Terms, the Operative Terms shall be deemed to be amended to the extent necessary to conform to the HOA, the Pre-Feed JVA, or other such agreements, as the case may be, notwithstanding the Parties' acknowledgements in Article 2.1(c) above.

**ARTICLE 3
TIMELINES**

3.1 Timeline Commitment

(a) TADI and the State shall use reasonable commercial efforts to finalize, execute and deliver the Alaska LNG Project Equity Option Agreement and the Alaska LNG Midstream Services Agreement as soon as commercially reasonable after the Trigger Event, not to exceed ninety (90) days after the Trigger Event, unless extended with the joint approval of the Parties.

(b) It shall be a condition precedent to the effectiveness of each Transition Agreement that each other Transition Agreement be fully executed and delivered to the applicable Parties.

3.2 Notice of Enabling Legislation. Within 30 days after the effective date of the Enabling Legislation each Party shall notify the other Parties in writing if the Enabling Legislation is not acceptable to it. If a Party fails to so notify the other Parties, then that Party shall be deemed to have given notice that the Enabling Legislation is acceptable.

**ARTICLE 4
TERM, TERMINATION AND REIMBURSEMENT**

4.1 Term and Termination

This MOU shall commence on the Effective Date hereof and shall terminate upon the earliest of:

- (a) execution and delivery of all of the Transition Agreements,
- (b) upon written notice from any Party pursuant to Section 3.2 that the Enabling Legislation is not acceptable;
- (c) upon written notice from one Party to the others if the Alaska LNG Project Equity Option Agreement has not been executed and delivered in accordance with Article 3;
- (d) upon written notice from one Party to the others if the Alaska LNG Midstream Services Agreement has not been executed and delivered in accordance with Article 3; or
- (e) one hundred twenty (120) days after the Trigger Event, unless extended with the joint approval of the Parties,
- (f) upon the last date that Enabling Legislation could be enacted in 2014 by the Legislature, but has not been enacted, or if enacted in 2014 and vetoed, the last date the veto could be overridden; or
- (g) July 31, 2014, unless extended with the joint approval of the Parties.

4.2 Development Cost Reimbursement

Provided the Enabling Legislation becomes effective:

(a) If this MOU is terminated for any reason other than pursuant to Section 4.1(a), State shall reimburse TADI for all the post-December 31, 2013 development costs plus an amount equal to the associated AFUDC, at a rate of 7.1%, net of AGIA reimbursement received and retained by the Licensees under AGIA Project Plan Amendment 1B, that have been incurred or committed to by TADI or its

Affiliates under the CSA and the Pre-FEED JVA, including but not limited to TADI's share of contract cancellation penalties and continued funding obligations under such agreements, through the date of termination.

(b) State obligation to reimburse TADI under this Section 4.12 shall be TADI's exclusive remedy in law and equity for such termination.

4.3 Survival. This Article 4 shall survive termination of the MOU.

ARTICLE 5 RELATIONSHIP OF THE PARTIES

5.1 Relationship of the Parties. Neither this MOU nor any other documentation or communication between the Parties shall constitute or create a joint venture, partnership, legal entity, or other similar business combination or arrangement between the Parties. Each Party shall act only on an individual and several basis. No Party shall have the right to act as an agent for or a servant or employee of the other Parties, to make commitments or assume obligations for and on behalf of the other Parties, or to bind the other Parties for any purpose whatsoever.

ARTICLE 6 NOTICES

6.1 Notices. Any and all notices between the Parties given under or in relation to this MOU shall be in writing and shall be deemed to have been given if personally delivered, delivered and confirmed by telecopier or like instantaneous transmission device, delivered by a reputable overnight delivery service, or sent by certified mail (postage prepaid, return receipt requested), addressed as follows:

If to the State:

Joe Balash
Commissioner, Department of Natural Resources
550 W. 7th #1400
Anchorage, AK 99501
Phone: 907-269-8431
Facsimile: 907-269-8918
joe.balash@alaska.gov

Angela Rodell
Commissioner, Department of Revenue
P.O. Box 110400
Juneau, AK 99811-0400
Phone: 907-465-2300
Facsimile: 907-465-2389
angela.rodell@alaska.gov

If to Foothills, TADI or TC Alaska

Anthony Palmer
Vice President, Major Projects Development
TransCanada PipeLines Ltd.
450-1st Street, S.W.
Calgary, AB T2P 5H1
Phone: 403-920-2035
Facsimile: 403-920-2318
tony_palmer@transcanada.com

With a copy to:

c/o TransCanada
450-1st Street, S.W.
Calgary, AB T2P 5H1
Attn: Corporate Secretary
Facsimile: 403-920-2327

Any Party may at any time or from time to time designate, by written notice to the other Parties, another address in lieu of the address specified above.

ARTICLE 7 GOVERNING LAW AND EFFECT OF MOU

7.1 Governing Law and Jurisdiction. This MOU shall be governed by and construed in accordance with the laws of the Alaska, not including Alaska's choice of law provisions, and the federal laws applicable therein. The Parties do hereby irrevocably and unconditionally submit to the exclusive jurisdiction of the courts of the State of Alaska in connection with any disputes or other matters arising out of or in connection with this MOU.

ARTICLE 8 MISCELLANEOUS

8.1 Assignment. Except in the case of an assignment by a Party to an Affiliate in which event the assigning Party shall remain liable, no Party shall have the right to assign this MOU or any interest in this MOU without the prior written consent of the other Party, which consent may be withheld in the other Party's sole, absolute and unfettered discretion.

8.2 Severability. If any provision of this MOU or the application thereof shall be found by any court of competent jurisdiction to be invalid, illegal, or unenforceable, to any extent and for any reason, and if, after good faith efforts to negotiate replacement provisions, the Parties agree that this MOU should not be voided, it shall be adjusted rather than voided in order to achieve the intent of the Parties. If the Parties agree that this MOU should not be voided, and the intent of the Parties can be achieved, then the remainder of this MOU and the application of such remainder shall not be affected thereby, and shall be enforced to the greatest extent permitted by law. Otherwise, this MOU shall terminate.

8.3 Non-Waiver. No failure or delay by any Party in exercising any right, power, or privilege granted hereunder shall operate as a waiver thereof, nor shall any single or partial exercise thereof preclude any other or further exercise thereof or the exercise of any other right, power, or privilege hereunder.

8.4 Entire Agreement. This MOU constitutes the entire agreement between the Parties relating to the subject matter hereof, and it supersedes all prior and contemporaneous agreements, understandings, negotiations and discussions, whether oral or written, between the Parties with respect to the subject matter hereof.

8.5 Amendments. This MOU may not be modified or amended, in whole or in part, except by a supplemental written agreement signed by all Parties.

8.6 Construction. The Parties have participated jointly in the negotiation and drafting of this MOU. In the event an ambiguity or question of intent or interpretation arises, this MOU shall be construed as if drafted jointly by the Parties and no presumption or burden of proof shall arise favoring or disfavoring any Party by virtue of the authorship of any of the provisions of this MOU.

8.7 Counterparts; Multiple Originals. This MOU may be signed and delivered in counterparts with the same effect as if both Parties had signed and delivered the same copy, and when each Party has signed and delivered a counterpart, all counterparts together constitute one Agreement. Delivery of a copy of this Agreement by facsimile or other similar electronic means of communication is good and sufficient delivery.

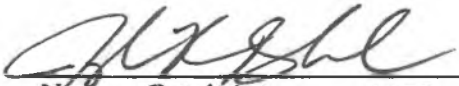
8.8 No Damages/Dispute Resolution. Except with regard to Section 4.2, no Party shall be liable to any other Party for damages of any kind or nature as a result of a breach or default of its obligations under this MOU. In the event of a breach, other than a breach of Section 4.2, the sole remedy available to a Party is the filing of an action for specific performance.

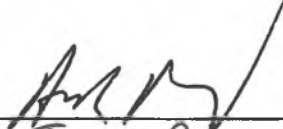
8.9 Article and Section Headings. The Article and Section headings used in this MOU have been inserted only for convenience to facilitate reference and shall not be determinative in construing the meaning, effect, or application, of any Article, Section, or provision hereof.


IN WITNESS WHEREOF, the Parties have signed this MOU as of the Effective Date.

THE STATE OF ALASKA

TRANSCANADA ALASKA COMPANY, LLC

By: 
Name: COMMISSIONER - DNR
Title: JOE BALASH

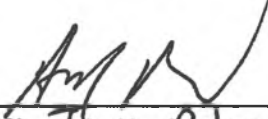
By: 
Name: Tony Palmer
Title: President

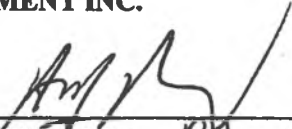
By: 
Name: Commissioner - Revenue
Title: Angela Russell

By: _____
Name:
Title:

FOOTHILLS PIPE LINES LTD.

TRANSCANADA ALASKA DEVELOPMENT INC.

By: 
Name: Tony Palmer
Title: President

By: 
Name: Tony Palmer
Title: President

By: _____
Name:
Title:

By: _____
Name:
Title:

IN WITNESS WHEREOF, the Parties have signed this MOU as of the Effective Date.


THE STATE OF ALASKA

**TRANSCANADA ALASKA COMPANY,
LLC**

By: _____
Name:
Title:

By: _____
Name:
Title:

By: _____
Name:
Title:

By: 
Name: David Kohlenberg
Title: Vice President.

FOOTHILLS PIPE LINES LTD.

**TRANSCANADA ALASKA
DEVELOPMENT INC.**

By: _____
Name:
Title:

By: _____
Name:
Title:

By: 
Name: **RON COOK**
Title: **VICE PRESIDENT - TAXATION**

By: 
Name: **RON COOK**
Title: **VICE PRESIDENT - TAXATION**

LEGAL	
CONTENT	



THE STATE
of **ALASKA**
GOVERNOR SEAN PARNELL

Department of Natural Resources

Joe Balash, Commissioner

Department of Revenue

Angela Rodell, Commissioner

December 12, 2013

Mr. Tony Palmer
Vice President, Major Projects Development
TransCanada Pipelines Limited
450 1st Street S.W.
Calgary, Alberta, T2P-5H1 Canada

Re: Approval of AGIA Licensees' December 9, 2013 Request for Project Plan Amendments

Dear Mr. Palmer:

We are in receipt of the December 9, 2013 request by TransCanada Alaska Company, LLC ("TC Alaska") and Foothills Pipe Lines Ltd. (jointly, the "Licensees" or "TransCanada") for approval of project plan amendments ("PPA Request #1B") under section 210 of the Alaska Gasline Inducement Act.¹ As discussed herein, we grant approval of PPA Request #1B to the extent necessary to perform additional work from approximately January 1, 2014, through the end of June, 2014, as further described in the work plan, time line and budget set forth in Appendix A of your application ("2014 Work").

By way of background, in the past two years Governor Parnell has laid out important benchmarks in his State of the State addresses that have sought to maintain and accelerate progress on Alaska gas commercialization and to ensure commensurate commitment by the Licensees and the Alaska North Slope Producers (ExxonMobil, BP and ConocoPhillips, jointly "ANS Producers") in commercializing North Slope gas for the benefit of Alaskans. In his 2012 State of the State address Governor Parnell established an important benchmark by calling on the ANS Producers and the AGIA Licensees to align under an AGIA framework for timely commercialization of North Slope natural gas resources for use in-state and for markets beyond Alaska. In March 2012, the ANS Producers and AGIA Licensees met this benchmark.²

¹ AS 43.90, *et seq.* ("AGIA"). Under section 210 of AGIA, the Commissioners may approve a proposal by the AGIA Licensees to change their project plan if, among other things:

[T]he amendment or modification is necessary because of changed circumstances outside the licensee's control and not reasonably foreseeable before the license was issued. An amendment or modification approved under this section must be consistent with the requirements of AS 43.90.130 and, except for an amendment or modification required because of an order or requirement of a regulatory agency with jurisdiction over the project or by the Alaska Oil and Gas Conservation Commission, may not substantially diminish the value of the project to the state or the project's likelihood of success.

² In his 2012 State of the State address, the Governor, among other things, also called on the relevant parties to reach a settlement in the state's interests on the long-standing Point Thomson dispute and litigation, and to harden numbers and an associated work schedule on an Alaskan LNG project. As we stated in PPA #1A, these

Specifically, in a March 30, 2012 letter in response to Governor Parnell, the chief executive officers of the ANS Producers announced that they and TransCanada “have aligned on a structured, stewardable and transparent approach with the aim to commercialize North Slope natural gas resources within an AGIA framework.” The ANS Producers and TransCanada also stated that they “are now working together” with a focus on “large-scale liquefied natural gas (LNG) exports from south-central Alaska . . . as an alternative to gas line exports through Alberta.”

On May 2, 2012, in the “PPA 1 Approval”, we approved two project plan amendments in furtherance of the alignment of the ANS Producers and the AGIA Licensees. Our PPA 1 Approval permitted the inclusion in the project plan of a revised work plan, time line and associated budget to facilitate participation by the Licensees and the Alaska Pipeline Project (“APP”) in an alternative that entailed a gas pipeline and related midstream facilities to deliver ANS natural gas to an LNG terminal located in South-Central Alaska. (This alternative was referred to as the “SCLNG” project, but is now referred to as the “AKLNG” project.) In addition, in the PPA 1 Approval we extended by two years to October 31, 2014, the date by which Licensees were to submit to the FERC an application for a certificate of public convenience and necessity. Additionally, we made the PPA 1 Approval subject to a number of conditions. As more fully set forth in the PPA 1 Approval, the Licensees were required (1) to conduct a solicitation of interest in support of the LNG alternative, (2) to consult with the Alaska Gasline Development Corporation (“AGDC”) in the interest of prudently avoiding unnecessary and duplicative expenditure of state funds, and (3) to complete an inventory of work product related to the Alaska-Alberta Project.

Subsequently, on June 11, 2013 we issued the PPA 1A Approval, which noted that the Licensees had made significant progress toward meeting the PPA 1 Approval conditions. Our PPA 1A Approval addressed two project plan amendments. First, we approved the performance of field work on the midstream component of the project through December 15, 2013. Second, we approved an extension of the FERC filing deadline by one year to October 31, 2015.

The Licensees now seek what is in effect a limited extension of the project plan amendments that we approved in the PPA 1A Approval. Specifically, in PPA Request #1B, the Licensees state (at page 2) that the “APP Parties and the ANS Producers have selected a SCLNG concept, and are planning ongoing work to support a potential SCLNG [project], including preliminary Pre-FEED studies and planning and 2014 field survey planning work” for the midstream pipeline facilities (the “2014 Work”). The Licensees anticipate this 2014 Work will span from approximately January 1, 2014 to the end of June, 2014. The Licensees also state that while the 2014 Work is being carried out, it will be necessary for the Licensees to continue limited work on existing elements of the Alaska-Alberta project to preserve rights.

For the reasons explained below, we grant the Licensees’ request to perform the 2014 Work. Further, we approve the work plan, timeline and budget in Appendix A of PPA Request #1B that defines the 2014 Work.

benchmarks were met. Importantly, construction of the multi-billion dollar development at Point Thomson has begun with over 30 Alaska companies and 1,000 Alaskans working on this project.

First, the Licensees' request to perform the 2014 Work is consistent with important project benchmarks established by Governor Parnell in his January 16, 2013 State of the State address. There, Governor Parnell called on the ANS Producers and the Licensees to select a concept for the SCLNG project by February 15, 2013. This benchmark was met on February 15, 2013, when the ANS Producers and TransCanada sent a letter to Governor Parnell reporting that they had completed the concept selection phase of the SCLNG project.³ In his State of the State address, Governor Parnell also called on the ANS Producers and Licensee to "ensure a full summer of field season work will commence this year". PPA Request 1A met this benchmark by proposing to perform the 2013 Work, which we approved. The Licensees' PPA Request #1B builds on the 2013 Work by providing for the additional 2014 Work. These are positive developments that help to maintain and accelerate the SCLNG project momentum, and continue the progress made since the Governor's 2012 State of the State address called on the parties to align under an AGIA framework for timely commercialization of North Slope natural gas resources, for use in-state and for markets beyond Alaska.

Second, and as we noted in the PPA 1A Approval, ANS gas commercialization efforts remain in a transition phase with the ANS Producers, the APP Parties, and the Licensees continuing to work together on a single effort. This PPA-1B Approval supplements the PPA 1 and PPA-1A Approvals to amend further the licensed Alaska-Alberta project to include the 2014 Work and advance this transition, pave the way for more intensive work in the future, and keep the project's ultimate costs as low as possible by helping to avoid a delay in the development of the project.⁴ Consistent with this PPA-1B Approval, the Licensees may submit costs incurred as qualified expenditures in connection with the 2014 Work for reimbursement under AGIA for the period covered in the revised work plan, timeline and budget in PPA Request 1B.

Third, and as further explained in the PPA 1 Approval and reiterated in the PPA 1A Approval, we find that changed circumstances continue to exist for purposes of AS 43.90.210.⁵ For example, the current efforts to develop the SCLNG project represent the continued alignment of the Licensees and all three ANS Producers on a gas commercialization effort. This is important progress that is furthered by approval here of the requested project plan amendments.

Lastly, our PPA 1A Approval required that all work product related to the 2013 Work generated by or on behalf of APP or the Licensees be transferred to the Licensees by December 31, 2013. Further, our PPA 1A Approval required the Licensees to inventory and preserve all work product related to the 2013 Work, including both complete and incomplete work, and provide the inventory to the Commissioners. These conditions continue to apply with respect to

³ A copy of the February 15, 2013 Letter, and its attachments appears as Appendix C to PPA Approval 1A.

⁴ PPA 1B does not modify the Alaska-Alberta destination point under the AGIA License.

⁵ As noted in the May 2, 2012 PPA 1 Approval, such changed circumstances include: (1) a substantial increase in U.S. shale gas reserve estimate compared to when the License was issued; (2) continuing significantly higher natural gas prices in Asia and other world markets relative to U.S. prices, reflecting a higher oil to natural gas price ratio; (3) EIA's updated projection that the United States will become a net exporter of natural gas in the future; and (4) the continued interest of the ANS Producers in aligning their work efforts behind an LNG alternative, which was not foreseeable at the time of the AGIA Findings and the subsequent issuance of the License in 2008.

the 2013 Work, provided that the Licensees have until June 30, 2014 to satisfy the foregoing two conditions. With respect to the 2014 Work, the same conditions apply, except that the deadline for the transfer of the work product performed under this PPA 1B Approval is June 30, 2014.

CONCLUSIONS

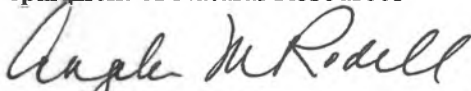
For the reasons discussed above, in the May 2, 2012 approval of PPA Request 1, and in the June 11, 2013 approval of PPA Request 1A, the Commissioners conclude as follows:⁶

1. PPA Request 1B consists of the request to perform the 2014 Work.
2. PPA Request 1B is necessary because of changed circumstances outside the Licensees' control and not reasonably foreseeable before the license was issued.
3. PPA Request 1B is consistent with the requirements of AS 43.90.130.
4. PPA Request 1B does not substantially diminish the value of the project to the state or the project's likelihood of success.
5. PPA Request 1B is approved as provided herein, subject to the conditions discussed herein.⁷

Sincerely,



Joe Balash
Commissioner
Department of Natural Resources



Angela Rodell
Commissioner
Department of Revenue

⁶ To the extent this determination does not address a specific statement or representation made in the PPA Request 1B, it should not be construed as agreement with any such statements or representations.

⁷ TransCanada asserts that PPA Request 1B contains proprietary information that is confidential under AGIA and that the Commissioners' March 15, 2012 determination of confidentiality under AGIA concerning PPA Request 1 supports treating PPA Request 1B on a confidential basis. To the extent that information in PPA Request 1B is proprietary, the Commissioners have determined that it is confidential under AGIA and the Commissioners' March 15, 2012 confidentiality determination.

**EXHIBIT B TO MEMORANDUM OF UNDERSTANDING
BETWEEN TRANSCANADA ALASKA COMPANY, LLC, FOOTHILLS PIPE LINES, LTD,
TRANSCANADA ALASKA DEVELOPMENT, INC.
AND THE STATE OF ALASKA**

ALASKA LNG PROJECT EQUITY OPTION TERM SHEET

This Term Sheet is attached to and made a part of the Memorandum of Understanding between the Parties and is subject to the terms and conditions of the MOU. Capitalized terms in this Term Sheet shall have the same meaning as in the MOU, unless the context suggests otherwise.

For purposes of the MOU, Section 2.1(c), the following sets forth the operative terms of this Equity Option Term Sheet ("Operative Terms"):

1. Upon execution of the Transition Agreements, TADI or its Affiliate would grant the State an exclusive and irrevocable right to acquire ("Option"), either for its own account or through a State Affiliate designated by the State acting through the Commissioners (the "Optionee"), up to 40% (see point 2 below) of the limited partnership interests in one or more limited partnerships (or similar entities; see point 10 below) (the "Limited Partnership") that would hold an equity participation interest (see point 2 below) in the PTU Gas Transmission Line, PBU Gas Transmission Line, GTP, and Gas Pipeline (collectively, the "Midstream Component").
2. The Parties intend that the Limited Partnership's equity participation interest in the Midstream Component would be equal to the greater of (a) the State's percentage share of the natural gas delivered to the Midstream Component by the ANS Producers from the State's total in-kind or in-value interest in the ANS Producer's natural gas production (whether royalty, production tax, or other gas in lieu of payment (collective, the "State's Share"), or (b) 14.0%. The Optionee's ownership interest in the Limited Partnership (maximum of 40%) would be subject to the condition that TADI's "net-net" ownership interest in the Midstream Component, through the Limited Partnership, must not be less than 14.0%.
3. The Limited Partnership Agreement would provide that TADI or its Affiliate would own 100% of the general partner of the Limited Partnership, and such general partner would hold a minimal (less than 1%) interest in the Limited Partnership. The General Partner would make all decisions on behalf of the Limited Partnership, provided that the Equity Option Agreement will provide that certain fundamental decisions (e.g. change to distribution policy, winding-up of Limited Partnership, sale of significant interest of Limited Partnership in AK LNG) could not be made without the approval of the Optionee (before the option is exercised) or the Limited Partner (after the option is exercised). The General Partner would be entitled to recover all of its reasonable direct and indirect costs that are associated with it acting as the general partner.
4. The Option would be exercisable one time only before its expiration. The Option would absolutely expire on the earlier of (i) December 31, 2015) (ii) the date of execution of commercial agreements for the commencement of FEED for the Alaska LNG Project, or (iii) the occurrence of any of the termination events listed in section 9 of the Alaska LNG Midstream Services Agreement Term Sheet (Exhibit C to the MOU), unless otherwise agreed in writing between TC and the Optionee.

5. The Optionee would not be entitled, except in the sole discretion of TADI, to exercise the Option in the event the Optionee or the State is in current default under the Transition Agreements or the Pre-FEED JVA. The Optionee and State will be provided with notice of and opportunity to cure such default.
6. Conditions on the Optionee exercising the Option would be:
 - a. A true up by the Optionee to the Limited Partnership of contributions, within 30 days of the exercise of the Option, of amounts contributed by the Limited Partnership to the Alaska LNG Project, at cost plus Allowance for Funds Used During Construction ("AFUDC"), at a rate of 7.1% for the purpose of this calculation, from date of contribution by the Limited Partnership until date of payment.
 - b. Commencing on the date of exercise of the Option, Optionee shall be responsible for its share of the Limited Partnership's operating costs and Alaska LNG Project costs and assume its obligations and liabilities as a limited partner pursuant to the Limited Partnership Agreement.
 - c. TADI and the State shall use commercially reasonable efforts to finalize, execute and deliver the Alaska LNG Project Equity Option Agreement, including the agreement establishing the Limited Partnership itself, as soon as commercially reasonable after the Trigger Event, not to exceed 90 days after the Trigger Event, unless extended with the joint approval of the Parties. TC and the SOA agree such agreements are intended to be consistent with the Operative Terms.
7. Conditions on the State transferring its interest in the Limited Partnership would be:
 - a. The State would be prohibited from transferring directly or indirectly (including through a change of control) all or any part of its limited partnership interest in the Limited Partnership to an entity (other than an entity that is a passive investor whose principal business is not natural gas transmission or oil transmission) that owns an interest in or operates one or more natural gas or oil transmission lines in North America; provided that the foregoing prohibition would not apply to restrict transfer by the State to a State Affiliate or a government fund at all times wholly owned by the State, such as the State Department of Revenue Constitutional Budget Reserve Fund (a "Fund").
 - b. Any proposed transfer by the State, including any proposed transfer to a Fund, would be subject to commercially reasonable creditworthiness requirements to be established in the Alaska LNG Project Equity Option Agreement. Any proposed transfer by the State to any person or entity other than (i) a Fund, or (ii) a State Affiliate, and any proposed transfer by a Fund or a State Affiliate to any person or entity, would be subject to a right of first refusal ("ROFR") in favour of TADI. Until Final Investment Decision ("FID"), TADI would waive its ROFR right with respect to a transfer of an interest in the Limited Partnership by the State when it is an integral part of a transfer to the same transferee of an equal or greater % ownership interest in the LNG Plant Component of the Alaska LNG Project.

- c. Any proposed transfer by the State would be subject to applicable transfer requirements and restrictions of the Alaska LNG Project agreements that the Limited Partnership is party to.
8. The Parties acknowledge the confidentiality provisions of the Alaska LNG Project agreements to which the Limited Partnership may become a party may prohibit or restrict disclosure of Project information to the State. The parties agree to use reasonable efforts to allow for disclosure to the State (including on a restricted basis) as required under applicable Alaska law.
9. TADI and the State agree that the Limited Partnership documentation shall, to the extent permitted by applicable law (as set forth in the Alaska LNG Project Equity Option Agreement), expressly disclaim fiduciary duties of the parties. The Limited Partnership documentation shall provide commercially reasonable contractual protections for the limited partners' rights, including the obligations of good faith and fair dealing between the Parties.
10. The structure for the Limited Partnership will utilize a limited liability company or similar structure which is tax-efficient for TADI, unless the State and TADI mutually agree on a different ownership structure. In all cases, respective roles, responsibilities and obligations of TADI and the State as set forth in the Operative Terms will remain applicable to the ownership structure selected.
11. The Parties acknowledge that this Exhibit B to the MOU will become a public document once the MOU to which it is attached is executed by the Parties.
12. The Optionee has no right to assign or transfer all or any portion of the Option, except to a State Affiliate.

**EXHIBIT C TO MEMORANDUM OF UNDERSTANDING
BETWEEN TRANSCANADA ALASKA COMPANY, LLC, FOOTHILLS
PIPE LINES, LTD, TRANSCANADA ALASKA DEVELOPMENT, INC.
AND THE STATE OF ALASKA**

ALASKA LNG MIDSTREAM SERVICES TERM SHEET

This Term Sheet is attached to and made a part of the Memorandum of Understanding between the Parties and is subject to the terms and conditions of the MOU. Capitalized terms in this Term Sheet shall have the same meaning as in the MOU, unless the context suggests otherwise.

For purposes of the MOU, Section 2.1(c), the following sets forth the operative terms of this Midstream Services Term Sheet ("Operative Terms"):

	KEY ITEMS	TERMS & CONDITIONS
	Enabling Legislation	This Term Sheet provides a framework to guide the Parties in the event of the enactment of the Enabling Legislation to negotiate and enter into a Precedent Agreement ("PA") (or similar agreement), and to negotiate and enter into a Firm Transportation Services Agreement ("FTSA") (or similar agreement). Capitalized terms shall have the same meaning as the Definitions in the Memorandum of Understanding ("MOU") to which this is attached, unless the context suggests otherwise.
	Consistency with Commercial Agreements	This Term Sheet, in its entirety, is subject to consistency with the commercial agreements already entered into or to be entered into with the ANS Producers for the Alaska LNG Project including agreements set forth in Section 2.1(e) of the MOU.
1.	Purpose & Objectives	Establish terms and conditions under which Transporter will provide to Shipper (A) GTP processing and (B) transportation services on the PTU Gas Transmission Line, PBU Gas Transmission Line and Gas Pipeline from GTP to delivery points within Alaska and to the LNG Plant in South Central Alaska in the Alaska LNG Project. The PTU Transmission Line, PBU Transmission Line, and Gas Pipeline are collectively defined as the "Pipelines".
2.	Transporter	"Transporter" means TADI or an Affiliate designated by TADI
3.	Shipper	"Shipper" means State of Alaska or an Affiliate designated by the State of Alaska
4.	Proposed Process of Agreements	<ol style="list-style-type: none"> 1. This Term Sheet is attached and made a part of the MOU, and it is subject to the terms and conditions of the MOU. 2. As provided in Article 2.1 and Article 3.1 of the MOU, the Shipper and Transporter will use commercially reasonable efforts to negotiate and enter into a Precedent Agreement ("PA") that captures the Operative Terms of this Term Sheet. 3. The Parties intend that the PA will be replaced with a Firm Transportation Services Agreement ("FTSA"). The FTSA will contain terms established in the PA and other customary terms typically found in FTSA's for similar services. The FTSA would

		be executed only after execution is approved by the Alaska Legislature and such approval is enacted into law.
5.	Daily Contracted Capacity	FTSA, with two-part reservation/usage rates, for capacity equal to the product of (i) the State Gas Share as defined in the HOA and (ii) the respective design capacity of the PTU Transmission Pipeline, PBU Transmission Pipeline, GTP and the Gas Pipeline.
6.	Key Processing and Transportation Commercial Terms	<ol style="list-style-type: none"> 1. Contract Term <ul style="list-style-type: none"> • Initial Contract Term ("ICT") of 25 years following commercial In-Service Date ("ISD"). ICT to be confirmed by Transporter and the Shipper prior to agreement with ANS Producers for Front End Engineering and Design ("FEED") for the Alaska LNG Project, provided that the ICT will not be less than 20 years. • FTSA Renewal Right means the rights described below under FTSA Renewal Right. If Shipper does not exercise its FTSA Renewal Right to extend the ICT, Transporter will have a Put Option (as described below under Put Option). 2. Toll Structure <ul style="list-style-type: none"> • Levelized revenue requirement based on cost-of-service toll making principles. • Reservation rate, a fixed charge expressed in \$/mmBtu/month, will be designed to capture Depreciation Recovery, Return on Equity ("ROE"), Cost of Debt, Income Taxes, fixed Operations and Maintenance Costs ("O&M"), property taxes and other non-income related taxes. Reservation rate payments will be made by Shipper regardless of actual GTP and Pipelines utilization by Shipper. • Usage rate, a variable charge expressed in \$/mmBtu, will be designed to capture variable O&M Costs. 3. Capitalization Structure <ul style="list-style-type: none"> • 70% debt and 30% equity during development and construction. Commencing on the 2nd anniversary of the ISD, and continuing through the term of the FTSA, the debt/equity ratio will be revised for rate purposes to 75% debt/25% equity. • 70% debt and 30% equity for Expansions and Maintenance Capital. 4. Rate Base <ul style="list-style-type: none"> • Initial Rate Base ("IRB") equal to the sum of prudent Capital Expenditures, ("CAPEX"), Allowance for Funds Used During Construction ("AFUDC"), property taxes paid during construction, and working capital. 5. Maintenance Capital <ul style="list-style-type: none"> • Maintenance capital will be capitalized and added to the Rate Base (in the manner described in "Capitalization Structure" above) and recovered over the then-remaining term of the FTSA 6. Return on Equity ("ROE") for Initial System. <ul style="list-style-type: none"> • Fixed at Final Investment Decision ("FID") at a base rate of 12.0% after tax, plus a Rate Tracker Differential (as defined below).

		<p>7. Cost of Debt for Initial System</p> <ul style="list-style-type: none"> • Fixed at FID at a base rate of 5.0%, plus a Rate Tracker Differential (as defined below). <p>8. Rate Tracker Differential</p> <ul style="list-style-type: none"> • The Rate Tracker Differential is the increase or decrease in the 30-year U.S. Treasuries yield at FID relative to such yield at the effective date of the MOU. <p>9. Depreciation Recovery</p> <ul style="list-style-type: none"> • 100% of CAPEX shall be recovered over the ICT through tolls. • CAPEX shall include the following items: <ul style="list-style-type: none"> • Prudently incurred CAPEX (including AFUDC and property taxes) after execution of the JVA pre-FEED Agreement, which shall be subject to review and audit by Shipper at its expense, in accordance with the principles set forth under "Review and Audit of CAPEX and O&M" below. • Prudently incurred CAPEX prior to the execution of the Pre-FEED JVA that is directly relevant to and utilized in advancing the AK LNG Project minus any amounts received by Transporter or its Affiliates from the State through AGIA reimbursement. • Transporter's Affiliate's share of costs incurred on the Alaska portion of the AGIA Project after December 5, 2008 and prior to execution of the Pre-FEED JVA (that have not otherwise been included in CAPEX through the operation of paragraph ii above) to the extent such costs do not exceed \$70 million minus any amounts received and retained by Transporter or its Affiliates from the State through AGIA reimbursement or from any State of Alaska entity for use of the data and assets associated with such costs. • No costs associated with the ANNGTC project may be included in CAPEX. • For toll design purposes, AFUDC will commence accrual upon approval by FERC of the project's request to initiate the pre-filing process. <p>10. Operations and Maintenance Costs</p> <ul style="list-style-type: none"> • Prudently incurred O&M costs and taxes other than income taxes (such as property taxes not otherwise included in rate base, fuel taxes, etc.) are annual flow-through costs to the account of the Shipper. O&M, and annual changes, shall be subject to annual review and audit by Shipper at its expense, provided that the audit is in accordance with the principles set forth under "Review and Audit of CAPEX and O&M" below. • In consultation with Shipper, Transporter will negotiate an appropriate allocation of project indirect costs, including cost of sharing facilities, allocated labor and overhead charges with the ANS Producers. With respect to Transporter owner's costs, allocation will be in accordance with Transporter allocation policy as approved by the NEB unless otherwise agreed by the
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		<p>parties.</p> <ul style="list-style-type: none"> • Variances in actual costs will be trued-up in the determination of the following year revenue requirement. <p>11. Income Taxes</p> <ul style="list-style-type: none"> • Calculated and collected on a normalized basis. • Expenses associated with new taxes and changes to tax rate are flowed-through to the account of Shipper <p>12. Interruption of Firm Service, including Force Majeure ("FM")</p> <ul style="list-style-type: none"> • Shipper continues to make full payment during periods of service interruption. • For Transporter's capacity on the Pipelines and GTP, all firm shippers (in-state and export LNG) shall have priority over interruptible shippers. In the event transportation service cannot be scheduled to all firm shippers on any day for any reason, capacity shall be scheduled first to deliver to utility customers, and then pro rata among other firm shippers. <p>13. Make-up Rights</p> <ul style="list-style-type: none"> • Make-up rights will be granted for any processing and/or transportation capacity or service offered by Transporter and paid for, but not taken, by Shipper. • Make-up rights can be exercised pro-rata with other firm shippers' make-up rights whenever Transporter has excess processing and/or transportation capacity beyond the amount that it requires for satisfying its firm shippers' capacity requirement. • Any unused Make-up Rights will expire at end of the contract term, including any extensions or renewals. <p>14. Provision of Third Party Services</p> <ul style="list-style-type: none"> • For third party GTP processing and Pipelines transportation services that do not involve investment of incremental capital, 90 percent of all net income (gross revenues minus incremental costs) received by Transporter from sources other than the FTSA, including but not limited to interruptible ("IT"), overrun, backhaul, or park and loan services shall be credited to the account of Shipper (to reflect the undertaking of Shipper to pay for 100% of the initial system Rate Base); • The minimum rate for IT service shall be no less than the 100 percent load factor equivalent of the firm rate paid by Shipper • Shipper shall only pay variable costs for IT, overrun, and backhaul services that do not involve incremental capacity as a result of expansions. • Subject to meeting the Creditworthiness Requirements, Shipper shall have the right to temporarily release unused capacity to third-parties at a rate to be negotiated between Shipper and the temporary replacement shipper. A release of capacity through temporary assignment/release does not release Shipper from its obligations under the FTSA. <p>15. Fuel Gas, Line Pack, Lost and Unaccounted for Gas</p> <ul style="list-style-type: none"> • Provided by Shipper as in-kind gas contribution; or purchased under a charged fuel rate at Shipper option, in which case the
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		<p>charged fuel expense will be included as a separate charge.</p> <ul style="list-style-type: none"> • No allocation of fuel shall be allocated to backhaul services • Fuel utilization to be allocated among all shippers based on actual monthly throughput. <p>16. Return of Extracted Gas to Shipper</p> <ul style="list-style-type: none"> • Extracted acid gas (CO₂, H₂S and other impurities) will be returned to Shipper for disposal or further processing at the outlet of the GTP <p>17. In-State Gas Uses</p> <ul style="list-style-type: none"> • Minimum 5 in-state off-take points for non-LNG consumption • Three tariff zones <ul style="list-style-type: none"> • Zone 1 – from North Slope to Nenana • Zone 2 – deliveries to Big Lake (South Central) • Zone 3 – deliveries to the LNG plant for LNG exports • Rates to be designed in consultation with Shipper to reflect a cost allocation principle based on weighted average volumetric-mile between deliveries to each zone <p>18. GTP Processing and Pipeline Transportation Services</p> <ul style="list-style-type: none"> • Processing services at the GTP and transportation services on the Pipelines will be offered separately to accommodate different needs of shippers <p>19. FTSA Renewal Right</p> <ul style="list-style-type: none"> • Shipper shall have the option, exercisable not later than 2 years prior to the end of the ICT (the “Renewal Date”) to renew the FTSA with Transporter for all or part of its Daily Contracted Capacity after the expiration of the ICT on an annual basis at a negotiated rate based on (i) a cost-of-service calculation computed on the net book value of Transporter equity interest in the underlying facilities used to provide GTP processing and pipeline transportation services to Shipper, with the rate recalculated to spread remaining Rate Base over the extended term of the FTSA, and (ii) the same toll setting terms such as “Capitalization Structure”, O&M, and “Income Taxes” set forth above, except that the rate applicable for the extension shall be based on a “Cost of Debt” and an ROE to be negotiated based on conditions existing at the time, and (iii) the contracted capacity as renewed by Shipper; provided, however, that the costs and capacity related to any expansion facilities priced incrementally shall be excluded from such computation. In the event that the net book value of the facilities has been or will be substantially depreciated as of the expiry of the ICT, parties shall consider in good faith reasonable compensation for Transporter to continue its role as service provider. <p>20. Buy-Back Right</p> <ul style="list-style-type: none"> • If as of the Renewal Date, Shipper has not exercised its right to renew the FTSA Shipper shall have a one-time option, exercisable by notice to Transporter within 60 days of the Renewal Date (the “Buy-Back Notice Date”), to buy from Transporter as of the end of the ICT its equity interest in Alaska LNG Project at a purchase price equal to the net book value of
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Transporter equity interest in the underlying facilities used to provide GTP processing and pipeline transportation services as of the end of ICT. Any associated assignment shall be made on an "as is, where is" basis, without representation or warranty of any kind by Transporter.

21. Put Option

- If: (i) as of the Renewal Date, Shipper has not exercised its right to renew the FTSA by five or more years, and (ii) as of the Buy-Back Notice Date Shipper has not exercised the Buy-Back Right, Transporter shall have the option, exercisable by notice to Shipper within 90 days of the Buy-Back Notice Date, to put to Shipper its equity interest in Alaska LNG Project at a purchase price equal to the net book value of Transporter equity interest in the facilities used to provide GTP processing and pipeline transportation services as of the end of ICT, with closing subject to legislative enactment. Any associated assignment shall be made on an "as is, where is" basis, without representation or warranty of any kind by Transporter.

22. Review and Audit of Pipelines and GTP CAPEX and O&M

- Shipper and Transporter agree to develop a protocol and process (the "Audit Protocol") for Shipper to access certain Alaska LNG Project information to facilitate Shipper review and audit of costs and expenses (capital and operating), which will have to be consistent with the HOA and subsequent agreements with the ANS Producers for the Alaska LNG Project. The Audit Protocol will be appended to the PA and FTSA, and include at minimum, the following items:
 - the audit shall be conducted by an independent auditing firm selected pursuant to State procurement code based on minimum qualifications to be agreed upon by the Shipper and Transporter for such procurement; and
 - the audit rights shall be exercised through such independent auditing firm, who shall be required to abide by confidentiality restrictions to be agreed between Transporter and Shipper.
- The principles in the Audit Protocol for reviewing and auditing the Pipelines and GTP CAPEX and O&M are as follows:
 - Any costs incurred shall be deemed to be prudently incurred if they are pursuant to (1) an approved Work Program and Budget for capital expenditures (WP&B) for the Alaska LNG Project that was submitted to and approved by Shipper or any associated entity of the Shipper in advance, (2) an Alaska LNG Project Operating Budget that was submitted to and approved by Shipper or any associated entity of the Shipper in advance, (3) the emergency HSE provisions of any underlying agreement, or (4) the approval of the Shipper or any associated entity of the Shipper. In the event the Shipper or any associated entity of the Shipper does not respond to any request for approval, as set out in (1), (2),

		<p>or (4) above, within ten (10) business days (or such shorter period as set out in the agreements or resolutions for the Alaska LNG Project) the Shipper will be deemed to have approved the costs incurred. If the Shipper does respond but does not approve, the Transporter shall raise the concern and vote not to approve as part of the approval process under the applicable Alaska LNG Project agreements, and so long as the Transporter does so such costs shall be deemed prudent if they are approved despite the Transporter's vote to disapprove under the applicable Alaska LNG Project agreement.</p> <ul style="list-style-type: none"> • For the avoidance of doubt, (a) personnel charge out rates, including annual adjustments, as provided in the relevant Alaska LNG Project agreement shall not be subject to review and audit, and (b) any expenditures in excess of budgeted amounts that are in accordance with the limitations in the applicable Alaska LNG Project agreements that do not require further management committee approvals (currently set at 105% of budget) shall be deemed to be prudently incurred. <p>23. Assignment</p> <ul style="list-style-type: none"> • Shipper may assign its rights and obligations under the FTSA to an Affiliate or third party with Transporter's consent (not to be unreasonably withheld), provided the transferee assumes in writing such rights and obligations on terms and conditions satisfactory to Transporter, including the creditworthiness standards set forth in paragraph 10 below.
7.	Pipelines and GTP Expansions	<ul style="list-style-type: none"> • In consultation with Shipper, Transporter will expand the GTP and Pipelines when requested by creditworthy shippers on terms that are acceptable to Transporter. Transporter will act reasonably in negotiating expansion terms with the expansion shipper. The capitalization structure for expansion shall be consistent with that set forth above. The ROE for expansion shall be reflective of the risk of such expansion and the cost of capital environment existing at the time. In the event Transporter fails to reach agreement with the expansion shipper, Shipper or its transferee/assignee (including State Affiliates and independent third parties not affiliated with the State or any State Affiliate) has the right to offer expansion terms, in its sole discretion, to such shipper and undertake the expansion as a direct participant in Alaska LNG Project and consistent with the principles established in this section. • Upon request by potential expansion shipper, Transporter will provide to the potential expansion shipper and Shipper estimated rates which the potential expansion shipper would have to pay for receiving Pipelines transportation and/or GTP processing services. Shipper and Transporter agree that no regulatory agency can mandate an expansion or set expansion terms unless required by applicable law. • Expansions must be in reasonable engineering increments and on commercially reasonable terms, including but not limited to full

		<p>recovery of expansion CAPEX over the expansion term</p> <ul style="list-style-type: none"> • Expansions for In-State Uses and Export LNG <ul style="list-style-type: none"> ○ Expansions to be undertaken on a sole risk basis ○ Expansion tolls and fuel assessments will be determined based on a methodology such as incremental and/or rolled in, as determined by the Shipper. The methodology will be established prior to entering into FEED.
8.	Development Cost Reimbursement	<ul style="list-style-type: none"> • If Shipper or Transporter exercises its right to terminate pursuant to any of the Termination Events set forth below, the Shipper shall pay Transporter for all the development costs incurred by Transporter after December 31, 2013 under the Pre-FEED JVA or FEED Agreement with the ANS Producers, including but not limited to contract cancellation penalties and continued funding obligations under such agreements, through the date of termination. The Shipper's payment of development costs shall be net of all AGIA payments received and retained by the AGIA Licensee relating to Transporter's share of development costs for activities authorized under AGIA Project Plan Amendment 1B. • Shipper will further pay Transporter an amount equal to the associated AFUDC, at a rate of 7.1% for the purpose of this calculation, on such development costs if (i) such termination is exercised by Shipper or (ii) Transporter exercises the termination due to the failure of the Alaska Legislature to ratify the MOU, or the subsequent FTSA, or Shipper's failure to meet the Creditworthiness Requirements at any time. • Shipper's obligation to reimburse Transporter for such costs shall be Transporter's exclusive remedy in law and equity for such termination.
9.	Termination Event	<p>Shipper's Rights To Terminate (Shipper Termination Event):</p> <ul style="list-style-type: none"> • Prior to FEED: <ul style="list-style-type: none"> • Any time provided a 90-day notice is given to Transporter. • From start of FEED through FID: <ul style="list-style-type: none"> • Within 60 days from the date one or more ANS Producers or Transporter withdraws from the Alaska LNG Project • At any time if Shipper (or the ANS Producers, if the SOA elects RIV) is unable to sign agreements to sell all of its royalty or tax gas on terms acceptable to Shipper. • At FID, for any reason. <p>Transporter Rights To Terminate (Transporter Termination Event):</p> <ul style="list-style-type: none"> • Legislature fails to provide statutory authority to DNR/DOR to enter into PAs by June 30, 2014. • Shipper fails to execute the PA within the specified time. • Shipper fails to execute the FTSA by December 31, 2015. • Shipper fails to maintain the standard of Creditworthiness Requirements. Transporter shall provide notice to Shipper of a failure to meet such standards, and Shipper shall have a reasonable period to cure.

		<ul style="list-style-type: none"> • At FID, if all Transporter corporate/Board approvals have not been obtained. • Within 3 months from FID, if debt financing has not been secured on terms and conditions satisfactory to Transporter in its sole discretion <p>Either Transporter or Shipper may terminate:</p> <ul style="list-style-type: none"> • If term(s) of the FEED Agreement or Definitive Agreements is/are not acceptable to Shipper or Transporter • Within 90 days from the date of issuance of any final regulatory authorizations, certificates, or permits that includes material unacceptable condition(s) or requirement(s) to Transporter or Shipper • At FID, if not all right-of-ways, easement and land leases have been secured <p>Conveyance of Transporter Alaska LNG Project Interest to Shipper:</p> <ul style="list-style-type: none"> • Upon a Termination Event and payment to Transporter of the Development Costs, and the associated AFUDC, as applicable, Transporter shall assign all of its interest in the Pre-FEED JVA or the FEED Agreement, including all of its equity stake in the AKLNG Project, to the Shipper promptly without additional consideration. Any such assignment shall be made on an "as is, where is" basis, without representation or warranty of any kind by Transporter. • Within a period of 5 years of SOA exercising its termination right, if SOA participates in a pipeline project to commercialize North Slope gas that is substantially similar to the Alaska LNG Project, SOA shall offer to Transporter an option to participate in the GTP and Pipelines of such project on terms and conditions consistent with those set forth in this Term Sheet, except the cost of debt and ROE to be negotiated based on conditions existing at the time. The SOA shall not be obligated to offer the foregoing option to the Transporter if: <ul style="list-style-type: none"> i. the Transporter is in material default of the PA or FTSA at the time of the termination, and ii. the material default was capable of being remedied, and iii. Transporter was offered a reasonable time period to remedy the material default and failed to do so.
10.	Creditworthiness Requirements	<ul style="list-style-type: none"> • Shipper must meet and maintain the following creditworthiness standards through the term of the PA and FTSA. <ol style="list-style-type: none"> 1. A minimum of A- credit rating issued by Standard & Poor's or equivalent, and 2. Provide documentation satisfactory to Transporter that Shipper obligations under the PA or FTSA are supported with the full faith and credit of the State of Alaska (as a sovereign) or other dedicated revenue source acceptable to Transporter. • As an alternate to (1) and (2) above, Shipper could provide

		<p>collateral, in the form of cash or letter of credit in form and substance reasonably satisfactory to Transporter, of amount sufficient to cover Shipper's proportional share of (i) projected capital costs during development and construction, or (ii) payment obligations under the FTSA over the remaining term of the FTSA.</p> <ul style="list-style-type: none"> • Shipper continues to be liable for all obligations, including maintaining the creditworthiness standards, under the PA or FTSA if its capacity commitment is transferred to another party on a temporary basis such as through temporary release or assignment. This applies similarly to permanent assignment unless the assignee meets the appropriate creditworthiness standards. <ol style="list-style-type: none"> 1. For any assignee who is an Affiliate of the State, the creditworthiness standards will be the same as Shipper. 2. For any assignee who is not an Affiliate of the State, the creditworthiness standards will be: <ul style="list-style-type: none"> • A minimum of A- credit rating issued by Standard & Poor's or equivalent, and • A minimum Tangible Net Worth equal to its share of the projected capital cost for the period prior to In-Service Date ("ISD") and its share of the Rate Base for the period following the ISD.
11.	No Discriminatory Action by Shipper	Transition Agreements to contain commercial protection for discriminatory changes in law or other discriminatory actions to the extent permitted by applicable law.
12.	Dispute Resolution	FERC to be the arbiter of disputes under the PA and FTSA, provided FERC has jurisdiction over (i) the Pipelines and GTP components of the AK LNG and (ii) the rates and services provided by the Pipelines and GTP components of the AKLNG. The Parties intend that FERC (or any other applicable regulator having jurisdiction) should provide a ruling consistent with and not outside the scope of the PA or FTSA, as the case may be, when such agreement is read in its entirety.
13.	Term Sheet Not Stand Alone	This Term Sheet is an integral part of the MOU and is not a stand-alone agreement between the Parties or Shipper and Transporter. It sets forth the basis on which the Parties intend to proceed forward as they negotiate the PA, the FTSA, and other applicable or ancillary commercial agreements (collectively, the "Alaska LNG Midstream Services Agreements"). Neither Party shall be legally bound to enter into Alaska LNG Midstream Services Agreements, and entering into such Alaska LNG Midstream Services Agreements shall be at the sole discretion of each Party and subject to all necessary internal approvals of each Party. The Parties each acknowledge that (a) the Term Sheet does not contain all the terms and conditions that would be included in the legally binding Alaska LNG Midstream Services Agreements, and therefore, the Term Sheet does not constitute a binding commitment or offer or acceptance with respect to its terms or the transaction to be consummated; (b) it is the intention of the Parties that the PA and FTSA will be consistent with the commercial principles set out in this TS; and (c) the making of this Term Sheet or attachment of this Term Sheet to the MOU will not create any binding rights or obligations, as it is intended that neither party will have any right or obligations to

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		<p>complete the transactions contemplated in this Term Sheet unless and until the Precedent Agreement is executed and delivered at the sole discretion of each Party. The Alaska LNG Midstream Services Agreements may contain such other provisions as are negotiated by the Parties on reasonable commercial terms and conditions, based on industry practice in other comparable pipeline transportation arrangements.</p>
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